3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 85 percent of total emissions on a carbon (C) equivalent basis in 2005. This included 98, 38, and 11 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 82 percent of national emissions from all sources on a C equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 27,044 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2004, of which the United States accounted for about 22 percent.[1] Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, as well as indirect greenhouse gases such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs). Mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States, and overall energy-related activities were collectively the largest source of these indirect greenhouse gas emissions.

Figure 3-1: 2005 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2005 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. CO_2 emissions from these activities, however, are not included in national emissions totals because biomass fuels are of biogenic origin. It is assumed that the C released during the consumption of biomass is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to the atmosphere. The net impacts of land-use and forestry activities on the C cycle are accounted for within the Land Use, Land-Use Change, and Forestry chapter. Emissions of other greenhouse gases from the combustion of biomass and biomass-based fuels are included in national totals under stationary and mobile combustion.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 6,201.9 Tg CO_2 Eq. in 2005, an increase of 19 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005
CO_2	**4,886.1**	**5,212.8**	**5,773.2**	**5,690.2**	**5,740.7**	**5,803.8**	**5,911.5**	**5,942.7**
Fossil Fuel Combustion	4,724.1	5,030.0	5,584.9	5,511.7	5,557.2	5,624.5	5,713.0	5,751.2
Non-Energy Use of Fuels	117.3	133.2	141.0	131.4	135.3	131.3	150.2	142.4

[1] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Annual 2004* <http://www.eia.doe.gov/iea/carbon.html> EIA (2006).

Natural Gas Systems	33.7	33.8	29.4	28.8	29.6	28.4	28.2	28.2
Municipal Solid Waste Combustion	10.9	15.7	17.9	18.3	18.5	19.5	20.1	20.9
*International Bunker Fuels**	*113.7*	*100.6*	*101.1*	*97.6*	*89.1*	*83.7*	*97.2*	*97.2*
*Wood Biomass and Ethanol Consumption**	*219.3*	*236.8*	*228.3*	*203.2*	*204.4*	*209.6*	*224.8*	*206.5*
CH_4	**259.6**	**246.1**	**228.5**	**225.0**	**219.7**	**217.4**	**214.6**	**207.1**
Natural Gas Systems	124.5	128.1	126.6	125.4	125.0	123.7	119.0	111.1
Coal Mining	81.9	66.5	55.9	55.5	52.0	52.1	54.5	52.4
Petroleum Systems	34.4	31.1	27.8	27.4	26.8	25.8	25.4	28.5
Stationary Combustion	8.0	7.8	7.4	6.8	6.8	7.0	7.1	6.9
Abandoned Underground Coal Mines	6.0	8.2	7.3	6.7	6.1	5.9	5.8	5.5
Mobile Combustion	4.7	4.3	3.5	3.2	3.1	2.9	2.8	2.6
*International Bunker Fuels**	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**56.5**	**66.9**	**67.6**	**63.6**	**60.9**	**57.9**	**55.5**	**52.2**
Mobile Combustion	43.7	53.7	53.2	49.7	47.1	43.8	41.2	38.0
Stationary Combustion	12.3	12.8	14.0	13.5	13.4	13.7	13.9	13.8
Municipal Solid Waste Combustion	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.0*	*0.9*	*0.9*	*0.9*	*0.8*	*0.8*	*0.9*	*0.9*
Total	**5,202.2**	**5,525.8**	**6,069.2**	**5,978.9**	**6,021.4**	**6,079.1**	**6,181.7**	**6,201.9**

* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 3-2: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005
CO_2	**4,886,134**	**5,212,782**	**5,773,163**	**5,690,231**	**5,740,712**	**5,803,770**	**5,911,530**	**5,942,665**
Fossil Fuel Combustion	4,724,149	5,030,036	5,584,880	5,511,719	5,557,242	5,624,500	5,713,018	5,751,200
Non-Energy Use of Fuels	117,307	133,228	141,005	131,375	135,327	131,334	150,208	142,368
Natural Gas Systems	33,729	33,807	29,390	28,793	29,630	28,445	28,190	28,185
Municipal Solid Waste Combustion	10,950	15,712	17,889	18,344	18,513	19,490	20,115	20,912
*International Bunker Fuels**	*113,683*	*100,627*	*101,125*	*97,563*	*89,101*	*83,690*	*97,177*	*97,191*
*Wood Biomass and Ethanol Consumption**	*219,341*	*236,775*	*228,308*	*203,163*	*204,351*	*209,603*	*224,825*	*206,475*
CH_4	**12,360**	**11,718**	**10,879**	**10,714**	**10,463**	**10,352**	**10,221**	**9,862**
Natural Gas Systems	5,927	6,101	6,027	5,971	5,951	5,891	5,669	5,292
Coal Mining	3,899	3,165	2,662	2,644	2,476	2,480	2,597	2,494
Petroleum Systems	1,640	1,482	1,325	1,303	1,275	1,229	1,209	1,357
Stationary Combustion	382	373	351	324	324	334	340	330
Abandoned Underground Coal Mines	286	391	349	318	292	282	275	263
Mobile Combustion	226	207	165	154	146	136	131	125
*International Bunker Fuels**	*8*	*6*	*6*	*5*	*4*	*4*	*5*	*5*
N_2O	**182**	**216**	**218**	**205**	**197**	**187**	**179**	**168**
Mobile Combustion	141	173	172	160	152	141	133	123
Stationary Combustion	40	41	45	44	43	44	45	45

Municipal Solid Waste Combustion	2	1	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	*3*	*3*	*3*	*2*	*3*	*3*

* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

3.1. Carbon Dioxide Emissions from Fossil Fuel Combustion (IPCC Source Category 1A)

CO_2 emissions from fossil fuel combustion in 2005 increased by 0.7 percent from the previous year. This small increase is primarily a result of the restraint on fuel consumption caused by rising fuel prices, primarily in the transportation sector. Additionally, warmer winter conditions in 2005 decreased the demand for heating fuels. In contrast, warmer summer conditions in 2005 increased the demand for electricity. In 2005, CO_2 emissions from fossil fuel combustion were 5,751.2 Tg CO_2 Eq., or 22 percent above emissions in 1990 (see Table 3-3).[2]

Table 3-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	1995	2000	2001	2002	2003	2004	2005
Coal	**1,699.0**	**1,805.5**	**2,053.9**	**1,997.2**	**2,003.3**	**2,043.3**	**2,058.6**	**2,093.6**
Residential	3.0	1.7	1.1	1.1	1.2	1.2	1.3	1.0
Commercial	11.8	11.1	8.8	9.2	8.6	7.8	9.6	8.0
Industrial	152.3	143.0	133.5	133.5	123.4	124.0	126.2	122.2
Transportation	NE	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,531.3	1,648.7	1,909.6	1,852.3	1,868.3	1,906.2	1,917.6	1,958.4
U.S. Territories	0.6	0.9	0.9	1.0	1.9	4.1	3.9	4.0
Natural Gas	**1,011.4**	**1,169.6**	**1,227.6**	**1,178.7**	**1,219.6**	**1,187.9**	**1,190.4**	**1,170.0**
Residential	240.0	264.3	272.0	260.5	266.9	278.4	266.2	262.8
Commercial	143.3	165.2	173.2	165.0	171.7	174.3	171.2	167.0
Industrial	415.3	472.2	464.0	426.2	435.6	421.2	421.8	387.0
Transportation	36.1	38.4	35.7	34.9	37.2	33.4	32.3	31.8
Electricity Generation	176.8	229.5	282.0	290.8	307.0	279.3	297.7	320.1
U.S. Territories	NO	NO	0.7	1.2	1.2	1.4	1.3	1.3
Petroleum	**2,013.3**	**2,054.6**	**2,303.0**	**2,335.5**	**2,333.9**	**2,392.9**	**2,463.6**	**2,487.2**
Residential	97.4	90.5	100.5	102.2	94.4	104.2	102.5	95.0
Commercial	69.2	50.1	50.3	50.9	45.5	54.5	52.5	50.9
Industrial	289.5	267.5	277.4	310.2	298.7	313.2	327.6	330.9
Transportation	1,427.9	1,551.8	1,748.7	1,723.3	1,775.1	1,777.1	1,832.2	1,861.0
Electricity Generation	101.8	60.7	91.5	102.0	79.1	98.1	100.1	102.3
U.S. Territories	27.6	34.0	34.6	46.8	41.1	45.8	48.7	47.2
Geothermal*	**0.40**	**0.34**	**0.36**	**0.35**	**0.37**	**0.37**	**0.37**	**0.37**
Total	**4,724.1**	**5,030.0**	**5,584.9**	**5,511.7**	**5,557.2**	**5,624.5**	**5,713.0**	**5,751.2**

NE (Not estimated)
NO (Not occurring)
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates

[2] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

CO_2 emissions also depend on the source of energy and its C intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.[3] Producing a unit of heat or electricity using natural gas instead of coal can reduce the CO_2 emissions associated with energy consumption, and using nuclear or renewable energy sources (e.g., wind) can essentially eliminate emissions (see Box 3-2). Table 3-4 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-4: Annual Change in CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2001 to 2002		2002 to 2003		2003 to 2004		2004 to 2005	
Electricity Generation	Coal	16.0	1%	38.0	2%	11.4	1%	40.8	2%
Electricity Generation	Natural Gas	16.1	6%	-27.7	-9%	18.4	7%	22.4	8%
Electricity Generation	Petroleum	-22.9	-22%	19.0	24%	2.0	2%	2.2	2%
Transportation[a]	Petroleum	51.8	3%	2.0	0%	55.1	3%	28.8	2%
Residential	Natural Gas	6.4	2%	11.5	4%	-12.2	-4%	-3.4	-1%
Commercial	Natural Gas	6.6	4%	2.6	2%	-3.1	-2%	-4.2	-2%
Industrial	Coal	-10.1	-8%	0.6	0%	2.3	2%	-4.0	-3%
Industrial	Natural Gas	9.4	2%	-14.5	-3%	0.6	0%	-34.8	-8%
All Sectors[b]	**All Fuels[b]**	**45.5**	**1%**	**67.3**	**1%**	**88.5**	**2%**	**38.2**	**1%**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

In the United States, 86 percent of the energy consumed in 2005 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (6 percent), primarily hydroelectric power and biofuels (EIA 2006a). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 44 percent of total fossil fuel based energy consumption in 2005. Natural gas and coal followed in order of importance, each accounting for 28 percent of total consumption. Petroleum was consumed primarily in the transportation end-use sector, the vast majority of coal was used in electricity generation, and natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2006a).

Figure 3-3: 2005 U.S. Energy Consumption by Energy Source

[3] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Figure 3-5: 2005 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[4] These other C containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, it is assumed that all the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2005, weather conditions became warmer in both the winter and summer. The winter was slightly milder than usual, with heating degree days in the United States 5 percent below normal (see Figure 3-6). Warmer winter conditions led to a decrease in demand for heating fuels. Summer temperatures were substantially warmer than usual, with cooling degree days 15 percent above normal (see Figure 3-7) (EIA 2006f),[5] thereby increasing the demand for electricity.

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2005)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2005)

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[6]) of existing plants in 2005 remained high at slightly over 89 percent. Electricity output by hydroelectric power plants decreased in 2005 by approximately 1 percent. Electricity generated by nuclear plants in 2005 provided almost 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2006a). Aggregate nuclear and hydroelectric power plant capacity factors since 1973 are shown in Figure 3-8.

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[4] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

[5] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

[6] The capacity factor is defined as the ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full-power operation during the same period (EIA 2006a).

Figure 3-8: Aggregate Nuclear and Hydroelectric Power Plant Capacity Factors in the United States (1974–2005)

[END BOX]

For the purpose of international reporting, the Intergovernmental Panel on Climate Change (IPCC) (IPCC/UNEP/OECD/IEA 1997) recommends that particular adjustments be made to national fuel consumption statistics. Certain fossil fuels can be manufactured into plastics, asphalt, lubricants, or other products. A portion of the C consumed for these non-energy products can be stored (i.e., sequestered) indefinitely. To account for the fact that the C in these fuels ends up in products instead of being combusted (i.e., oxidized and released into the atmosphere), consumption of fuels for non-energy purposes is estimated and subtracted from total fuel consumption estimates. Emissions from non-energy uses of fuels are estimated in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter.

According to the UNFCCC reporting guidelines, CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., international bunker fuels) should be reported separately, and not included in national emission totals. Estimates of international bunker fuel emissions for the United States are provided in Table 3-5.

Table 3-5: CO_2 Emissions from International Bunker Fuels (Tg CO_2 Eq.)*

Vehicle Mode	1990	1995	2000	2001	2002	2003	2004	2005
Aviation	45.7	50.2	59.9	58.7	61.1	58.8	62.2	62.6
Marine	68.0	50.4	41.3	38.9	28.0	24.9	34.9	34.6
Total	**113.7**	**100.6**	**101.1**	**97.6**	**89.1**	**83.7**	**97.2**	**97.2**

* See International Bunker Fuels section for additional detail.
Note: Totals may not sum due to independent rounding.

End-Use Sector Consumption

An alternative method of presenting CO_2 emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. For the discussion below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption. This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. After the end-use sectors are discussed, emissions from electricity generation are addressed separately. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 3-6 and Figure 3-9 summarize CO_2 emissions from direct fossil fuel combustion and pro-rated electricity generation emissions from electricity consumption by end-use sector.

Table 3-6: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1995	2000	2001	2002	2003	2004	2005
Transportation	**1,467.0**	**1,593.3**	**1,787.8**	**1,761.5**	**1,815.7**	**1,814.8**	**1,868.9**	**1,897.9**
Combustion	1,464.0	1,590.2	1,784.4	1,758.2	1,812.3	1,810.5	1,864.5	1,892.8
Electricity	3.0	3.0	3.4	3.3	3.4	4.3	4.4	5.2
Industrial	**1,539.8**	**1,595.8**	**1,660.1**	**1,596.6**	**1,575.5**	**1,595.1**	**1,615.2**	**1,575.2**
Combustion	857.1	882.7	875.0	869.9	857.7	858.3	875.6	840.1
Electricity	682.7	713.1	785.1	726.7	717.8	736.8	739.6	735.1
Residential	**929.9**	**995.4**	**1,131.5**	**1,124.8**	**1,147.9**	**1,179.1**	**1,175.9**	**1,208.7**
Combustion	340.3	356.4	373.5	363.9	362.4	383.8	369.9	358.7
Electricity	589.6	639.0	758.0	760.9	785.5	795.3	806.0	849.9
Commercial	**759.2**	**810.6**	**969.3**	**979.7**	**973.8**	**984.2**	**999.1**	**1,016.8**
Combustion	224.3	226.4	232.3	225.1	225.7	236.6	233.3	225.8

Electricity	534.9	584.2	736.9	754.6	748.0	747.6	765.8	791.0
U.S. Territories	**28.3**	**35.0**	**36.2**	**49.0**	**44.3**	**51.3**	**54.0**	**52.5**
Total	**4,724.1**	**5,030.0**	**5,584.9**	**5,511.7**	**5,557.2**	**5,624.5**	**5,713.0**	**5,751.2**
Electricity Generation	**1,810.2**	**1,939.3**	**2,283.5**	**2,245.5**	**2,254.7**	**2,284.0**	**2,315.8**	**2,381.2**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

Figure 3-9: 2005 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

Transportation End-Use Sector

Using this allocation method, the transportation end-use sector accounted for 1,897.9 Tg CO_2 in 2005, or approximately 33 percent of total CO_2 emissions from fossil fuel combustion, the largest share of any end-use economic sector.[7] Between 1990 and 2005, transportation CO_2 emissions increased by 431.0 Tg CO_2, representing approximately 41 percent of the growth in energy-related CO_2 emissions from all sectors. Almost all of the energy consumed in the transportation sector was petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil.

Table 3-7 provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. As detailed in the table, overall transportation CO_2 emissions increased by 29 percent from 1990 to 2005, representing an average annual increase of 1.8 percent. Between 2004 and 2005 transportation CO_2 emissions increased by 1.6 percent.

Transportation fuel consumption is broadly affected by travel activity and the amount of energy vehicles use to move people and goods by various travel modes. In the short-term, changes in transportation energy consumption and CO_2 emissions primarily reflect variation in travel activity that accompanies year-to-year economic fluctuations. Long-term factors, especially the cost of fuel, can impact travel patterns and vehicle energy efficiency. Since 1990, there has been a significant increase in vehicle miles traveled (VMT) by light-duty trucks, freight trucks and aircraft. At the same time, the fuel economy of light-duty trucks and freight trucks has remained roughly constant. By contrast, commercial aircraft have become noticeably more fuel efficient and have operated with an increasing percentage of seats occupied.

As shown in Table 3-7, automobiles and light-duty trucks (consuming both gasoline and diesel) accounted for approximately 61 percent of transportation CO_2 emissions in 2005. From 1990 to 2005, CO_2 emissions from automobiles and light-duty trucks increased roughly 25 percent (236.2 Tg CO_2). Over this period, automobile and light-duty truck VMT increased by 39 percent, outweighing a small increase in overall fleet fuel economy. Much of the small increase in overall fleet fuel economy resulted from the retirement of older, less fuel efficient vehicles. Figure 3-10 presents the overall sales-weighted fuel economy of new vehicles sold in the United States over the 1990 to 2005 time period. The trend for new vehicle fuel economy reflects a substantial increase in the sales of light-duty trucks when compared to the generally declining sales of automobiles (Figure 3-11).

Figure 3-10. Sales-Weighted Fuel Economy of New Automobiles and Light-Duty Trucks, 1990–2005

[7] Note that electricity generation is the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

Figure 3-11. Sales of New Automobiles and Light-Duty Trucks, 1990–2005

Carbon dioxide emissions from freight trucks[8] increased by 69 percent (157.7 Tg) from 1990 to 2005, representing the largest emissions rate increase of any major transportation mode. Fuel economy for the freight truck fleet was relatively constant over this period, while truck VMT increased by 51 percent. Aircraft[9] CO_2 emissions increased by approximately 3.4 percent (6.1 Tg CO_2) between 1990 and 2005, reflecting both an increase in emissions from commercial aircraft emissions and a decrease in domestic military aircraft emissions. While CO_2 emissions from commercial aircraft grew by approximately 14.8 percent (20.2 Tg CO_2) from 1990 to 2005, passenger miles traveled increased by 69 percent over the same period, reflecting improvements in the fuel efficiency of planes and an increasing percentage of occupied seats per plane. For further information on all greenhouse gas emissions from transportation sources, please refer to Table A-108 in Annex 3.2.

Table 3-7 provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. Fifty-seven percent of the emissions from this end-use sector in 2005 were the result of the combustion of motor gasoline in automobiles and light-duty trucks. Other trucks and jet aircraft were also significant contributors, respectively accounting for 20 and 12 percent of CO_2 emissions from the transportation end-use sector.[10] For information on CO_2 emissions from off-road equipment and vehicles (i.e., non-transportation mobile
sources), please refer to Table A-107 in Annex 3.2.

Table 3-7: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.)[a]

Fuel/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005
Gasoline	**961.7**	**1,029.7**	**1,121.9**	**1,127.1**	**1,155.8**	**1,159.5**	**1,180.8**	**1,182.4**
Automobiles	607.3	591.7	628.4	631.1	645.8	624.9	624.3	610.4
Light-Duty Trucks	302.1	386.4	441.6	445.3	458.8	488.5	509.8	524.9
Other Trucks[b]	37.9	35.5	35.3	34.3	34.8	29.9	30.3	30.6
Buses	0.3	0.4	0.4	0.3	0.3	0.3	0.4	0.4
Motorcycles	1.7	1.7	1.8	1.7	1.6	1.6	1.7	1.8
Boats (Recreational)	12.4	14.0	14.4	14.4	14.4	14.3	14.2	14.3
Distillate Fuel Oil (Diesel)	**272.7**	**325.1**	**401.0**	**401.6**	**415.1**	**421.8**	**447.3**	**462.3**
Automobiles	7.8	7.7	3.6	3.7	3.7	4.2	4.3	4.4
Light-Duty Trucks	11.3	14.7	17.3	17.0	17.5	21.9	23.4	25.0
Other Trucks[b]	188.3	234.9	307.5	308.5	322.7	324.8	337.5	353.4
Buses	7.9	8.6	10.2	9.3	8.8	9.6	13.8	14.0
Locomotives	35.1	39.2	41.7	41.8	41.5	42.4	44.8	45.2
Ships & Boats	10.7	10.9	14.4	16.0	15.7	12.9	16.5	13.6
Ships (Bunkers)	11.6	9.2	6.3	5.3	5.1	6.0	7.1	6.8
Jet Fuel[c]	**222.6**	**222.1**	**253.8**	**242.8**	**236.8**	**231.5**	**239.8**	**246.3**
Commercial Aircraft	136.3	142.8	164.2	152.6	145.7	143.9	147.2	156.5
Military Aircraft	34.3	23.8	20.5	22.5	20.4	19.9	21.0	17.6
General Aviation Aircraft	6.3	5.3	9.2	9.1	9.5	8.8	9.3	9.6
Aircraft (Bunkers)	45.7	50.2	59.9	58.7	61.1	58.8	62.2	62.6
Aviation Gasoline	**3.1**	**2.7**	**2.5**	**2.4**	**2.3**	**2.1**	**2.2**	**2.4**
General Aviation Aircraft	3.1	2.7	2.5	2.4	2.3	2.1	2.2	2.4
Residual Fuel Oil	**80.1**	**71.7**	**69.9**	**46.1**	**53.3**	**45.0**	**58.3**	**63.7**

[8] Includes "other trucks" fueled by gasoline, diesel and LPG.

[9] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not accounted for in national emission totals.

[10] These percentages include emissions from bunker fuels.

Ships & Boats[d]	23.7	30.5	34.9	12.6	30.5	26.2	30.4	36.3
Ships (Bunkers)[d]	56.4	41.2	35.0	33.6	22.8	18.8	27.9	27.4
Natural Gas	**36.1**	**38.4**	**35.7**	**34.9**	**37.2**	**33.4**	**32.3**	**31.8**
Automobiles	+	0.1	+	+	+	+	+	+
Light Trucks	+	+	+	+	+	+	+	+
Buses	+	0.1	0.4	0.5	0.6	0.7	0.7	0.7
Pipeline	36.1	38.2	35.2	34.4	36.6	32.7	31.5	31.1
LPG	**1.4**	**1.1**	**0.7**	**0.8**	**0.8**	**1.0**	**1.1**	**1.1**
Light Trucks	0.5	0.5	0.3	0.3	0.3	0.4	0.4	0.4
Other Trucks[b]	0.8	0.5	0.4	0.5	0.5	0.6	0.7	0.7
Buses	+	+	+	+	+	+	+	+
Electricity	**3.0**	**3.0**	**3.4**	**3.3**	**3.4**	**4.3**	**4.4**	**5.2**
Rail	3.0	3.0	3.4	3.3	3.4	4.3	4.4	5.2
Total (Including Bunkers)[e]	**1,580.7**	**1,693.9**	**1,888.9**	**1,859.1**	**1,904.8**	**1,898.5**	**1,966.0**	**1,995.1**
Total (Excluding Bunkers)[e]	**1,467.0**	**1,593.3**	**1,787.8**	**1,761.5**	**1,815.7**	**1,814.8**	**1,868.9**	**1,897.9**

Note: Totals may not sum due to independent rounding.

[a] This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.

[b] Includes medium- and heavy-duty trucks over 8,500 lbs.

[c] Due to a change in methodology for estimating jet fuel consumption by aircraft type, the amount of jet fuel assigned to commercial aircraft is higher than in previous inventories; the "other aircraft" category has also been eliminated as a result of this change in methodology.

[d] Fluctuations in emission estimates from the combustion of residual fuel oil are currently unexplained, but may be related to data collection problems.

[e] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

+ Less than 0.05 Tg CO_2 Eq.

Industrial End-Use Sector

The industrial end-use sector accounted for 27 percent of CO_2 emissions from fossil fuel combustion. On average, 53 percent of these emissions resulted from the direct consumption of fossil fuels for steam and process heat production. The remaining 47 percent was associated with their consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting.

The industrial end-use sector includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Primary Metals, Paper, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2006a and 2005b).

In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption is also affected by weather conditions.[11] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy intensive manufacturing products to less energy intensive products (e.g., from steel to computer equipment) also have a significant affect on industrial emissions.

From 2004 to 2005, total industrial production and manufacturing output increased by 3.3 and 4.0 percent, respectively (FRB 2006). Over this period, output increased for Paper, Food, and Nonmetallic Mineral Products,

[11] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

but declined for Petroleum Refineries, Chemicals, and Primary Metals (see Figure 3-12).

Figure 3-12: Industrial Production Indices (Index 1997=100)

Despite the growth in industrial output (56 percent) and the overall U.S. economy (55 percent) from 1990 to 2005, CO_2 emissions from the industrial end-use sector increased by only 2.3 percent. A number of factors are believed to have caused this disparity between rapid growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) improvements in energy efficiency. In 2005, CO_2 emissions from fossil fuel combustion and electricity use within the industrial end-use sectors were 1,575.2 Tg CO_2 Eq., or 2.5 percent below 2004 emissions.

Residential and Commercial End-Use Sectors

The residential and commercial end-use sectors accounted for an average 21 and 18 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing to about 70 and 78 percent of emissions from the residential and commercial end-use sectors, respectively. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2005, CO_2 emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,208.7 Tg CO_2 Eq. and 1,016.8 Tg CO_2 Eq., respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions (see Table 3-6). In the long-term, both end-use sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Emissions from natural gas consumption represent over 73 percent of the direct (not including electricity) fossil fuel emissions from the residential and commercial sectors. In 2005, natural gas emissions decreased by 1 and 2 percent, respectively, in each of these sectors, due to warmer conditions in the United States (see Figure 3-13).

Figure 3-13: Heating Degree Days[12]

Electricity sales to the residential and commercial end-use sectors in 2005 increased by 5 and 3 percent, respectively, from 2004. This trend can largely be attributed to the growing economy (3.2 percent), which led to increased demand for electricity. Increased air conditioning-related electricity consumption in these sectors was also attributable to the warmer summer (see Figure 3-14). Electricity-related emissions in both the residential and commercial sectors rose due to increased consumption; total emissions from the residential sector increased by 2.8 percent in 2005, with emissions from the commercial sector 1.8 percent higher than in 2004.

[12] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000.

Figure 3-14: Cooling Degree Days[13]

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2005. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-15).

Figure 3-15: Electricity Generation Retail Sales by End-Use Sector

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) categorizes electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,[14] while the other sectors consist of those producers that indicate their primary business is other than the production of electricity.

In 2005, the amount of electricity generated (in kWh) increased by 2.4 percent, largely due to the growing economy, expanding industrial production, and warmer summer conditions. However, CO_2 emissions increased by 2.8 percent, as a larger share of electricity was generated by coal. Coal and natural gas consumption for electricity generation increased by 2.1 percent and 7.5 percent, respectively, in 2005, and nuclear power decreased by 1.1 percent. As a result of the increase in coal consumption, C intensity from direct fossil fuel combustion increased slightly overall in 2005 (see Table 3-9). Coal is consumed primarily by the electric power sector in the United States, which accounted for 94 percent of total coal consumption for energy purposes in 2005. The amount of electricity generated from renewables decreased by 1.7 percent in 2005.

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is emitted as a product from their combustion. Useful energy, however, is generated in the United States from many other sources that do not emit CO_2 in the energy conversion process, such as renewable (i.e., hydropower, biofuels, geothermal, solar, and wind)

[13] Degree days are relative measurements of outdoor air temperature. Cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000.

[14] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

and nuclear sources.[15]

Energy-related CO_2 emissions can be reduced by not only lowering total energy consumption (e.g., through conservation measures) but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[16] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. Other sources of energy, however, may be directly or indirectly C neutral (i.e., 0 Tg CO_2 Eq./Btu). Energy generated from nuclear and many renewable sources do not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be C neutral; although these fuels do emit CO_2, in the long run the CO_2 emitted from biomass consumption does not increase atmospheric CO_2 concentrations if the biogenic C emitted is offset by the growth of new biomass.[17] The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-8 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-8: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990	1995	2000	2001	2002	2003	2004	2005
Residential[a]	57.3	56.6	56.7	56.9	56.6	56.8	56.9	56.7
Commercial[a]	59.6	57.8	57.3	57.6	57.1	57.4	57.6	57.5
Industrial[a]	63.8	62.7	62.6	63.5	63.0	63.4	63.5	64.0
Transportation[a]	71.0	71.0	71.0	71.0	71.0	71.0	71.1	71.1
Electricity Generation[b]	86.7	86.0	85.6	85.1	85.0	85.7	85.4	85.0
U.S. Territories[c]	74.1	74.1	73.2	73.6	73.7	74.1	74.0	74.1
All Sectors[c]	**72.7**	**72.2**	**72.6**	**72.7**	**72.5**	**72.8**	**72.9**	**73.1**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

In contrast to Table 3-8, Table 3-9 presents C intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have

[15] Small quantities of CO_2, however, are released from some geologic formations tapped for geothermal energy. These emissions are included with fossil fuel combustion emissions from the electricity generation. Carbon dioxide emissions may also be generated from upstream activities (e.g., manufacture of the equipment) associated with fossil fuel and renewable energy activities, but are not accounted for here.

[16] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[17] Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

been attributed to both electricity generation and the end-use sectors in which that electricity was eventually consumed.[18] This table, therefore, provides a more complete picture of the actual C intensity of each end-use sector per unit of energy consumed. The transportation end-use sector in Table 3-9 emerges as the most C intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass-based fuels used, such as ethanol. The "other end-use sectors" (i.e., residential, commercial, and industrial) use significant quantities of biofuels such as wood, thereby lowering the overall C intensity. The C intensity of the electricity generation sector differs greatly from the scenario in Table 3-8, where only the energy consumed from the direct combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit CO_2.

Table 3-9: Carbon Intensity from all Energy Consumption by Sector (Tg CO_2 Eq./QBtu)

Sector	1990	1995	2000	2001	2002	2003	2004	2005
Transportation[a]	70.8	70.6	70.6	70.5	70.5	70.4	70.3	70.2
Other End-Use Sectors[a, b]	57.6	56.5	57.9	58.4	57.6	58.1	58.0	58.5
Electricity Generation[c]	59.0	57.9	59.9	60.0	58.9	59.6	59.4	59.8
All Sectors[d]	**61.1**	**60.3**	**61.4**	**61.8**	**61.3**	**61.6**	**61.5**	**61.9**

[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.
[b] Other End-Use Sectors includes the residential, commercial, and industrial sectors.
[c] Includes electricity generation from nuclear and renewable sources.
[d] Includes nuclear and renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption.

By comparing the values in Table 3-8 and Table 3-9, a few observations can be made. The use of renewable and nuclear energy sources has resulted in a significantly lower C intensity of the U.S. economy. Over the fifteen-year period of 1990 through 2005, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of renewable and nuclear energy technologies have not changed significantly. Per capita energy consumption has fluctuated, but is now roughly equivalent to levels in 1990 (see Figure 3-16). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2006).

Figure 3-16: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

C intensity estimates were developed using nuclear and renewable energy data from EIA (2006a) and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed,

[18] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to electricity generation and the end-use sector in which electricity consumption occurred.

sectoral-based emission estimates (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector*. Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail (EIA 2006b). The United States does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Grillot (2006).[19]

   For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.[20]

   It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standard, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[21]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for six fuel categories—coking coal, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from Gambogi (2006), EFMA (1995), U.S. Census Bureau (1991 through 1994), U.S. Census Bureau (2006), USITC (2006), U.S. Census Bureau (2005), EIA (2005a), EIA (2001b), USAA (2006), USGS (1998 through 2002), USGS (1995), Corathers (2006), USGS (1991a through 2005a), USGS (1991b through 2005b), U.S. International Trade Commission (2006), U.S. International Trade Commission (2004), Onder and Bagdoyan (1993), and Johnson (2006).[22]

3. *Adjust for biofuels, conversion of fossil fuels, and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude (1) fuels with biogenic origins, (2) fuels created from other fossil fuels, and (3) exports of CO_2. Fuels with biogenic origins are assumed to result in no net CO_2 emissions, and must be subtracted from fuel consumption estimates. These fuels include ethanol added to motor gasoline and biomass gas used as natural gas. Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[23] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is

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[19] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 53 Tg CO_2 Eq. in 2005.

[20] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[21] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

[22] See sections on Iron and Steel Production, Ammonia Manufacture, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production in the Industrial Processes chapter.

[23] These adjustments are explained in greater detail in Annex 2.1.

subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol and biogas were collected from EIA (2006b) and data for synthetic natural gas were collected from EIA (2006e), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2001a), EIA (2004), EIA (2006e), and Kass (2005).

4. *Adjust Sectoral Allocation of Distillate Fuel Oil*. EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on FHWA Vehicle Miles Traveled (VMT) that indicated that the amount of distillate consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel consumption was adjusted higher to match the value obtained from the bottom-up analysis based on VMT. As the total distillate consumption estimate from EIA is considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2005), Benson (2002 through 2004), DOE (1993 through 2004), EIA (2006a), EIA (1991 through 2005), EPA (2004), and FHWA (1996 through 2006).

5. *Adjust for fuels consumed for non-energy uses*. U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion, these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2006b).

6. *Subtract consumption of international bunker fuels*. According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[24] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2006) supplied data on military jet fuel use. Commercial jet fuel use was obtained from BEA (1991 through 2006) and DOT (1991 through 2006); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2006). Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions are discussed further in the section entitled International Bunker Fuels.

7. *Determine the total C content of fuels consumed*. Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's *Emissions of Greenhouse Gases in the United States 2005* (EIA 2006c) and EIA's *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail EIA (EIA 2006b). They are presented in Annexes 2.1 and 2.2.

8. *Estimate CO_2 Emissions*. Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).

9. *Allocate transportation emissions by vehicle type*. This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector.

[24] See International Bunker Fuels section in this chapter for a more detailed discussion.

- For highway vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2006); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2004).

- For non-highway vehicles, activity data were obtained from AAR (2005), BEA (1991 through 2006), Benson (2002 through 2004), DOE (1993 through 2004), DESC (2006), DOC (1991 through 2006), DOT (1991 through 2006), EIA (2006a), EIA (2006d), EIA (2006g), EIA (2002), EIA (1991 through 2005), EPA (2004), and FAA (2005).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) System for assessing Aviation's Global Emission (SAGE) model.[25] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2006a) and USAF (1998).[26]

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2005. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-

[25] FAA's System for assessing Aviation's Global Emissions (SAGE) model develops aircraft fuel burn and emissions for all commercial flights globally in a given year. The SAGE model dynamically models aircraft performance, fuel burn, and emissions, and is based on actual flight-by-flight aircraft movements. See <http://www.faa.gov/about/office_org/headquarters_offices/aep/models/sage/>.

[26] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions. In particular, residual fuel consumption data for marine vessels are highly uncertain, as shown by the large fluctuations in emissions that do not mimic changes in other variables such as shipping ton miles.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant inventory variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 150 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[27] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency-personnel.[28]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[29] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-10. Fossil fuel combustion CO_2 emissions in 2005 were estimated to be between 5,656.3 and 6,060.1 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2005 emission estimate of 5,751.2 Tg CO_2 Eq.

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[27] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[28] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[29] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Table 3-10: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal[b]	**2,093.6**	**2,024.6**	**2,290.6**	**-3%**	**+9%**
Residential	1.0	0.9	1.1	-5%	+15%
Commercial	8.0	7.6	9.2	-5%	+15%
Industrial	122.2	117.5	142.3	-4%	+16%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,958.4	1,882.7	2,146.7	-4%	+10%
U.S. Territories	4.0	3.5	4.7	-12%	+19%
Natural Gas[b]	**1,170.0**	**1,179.5**	**1,245.4**	**1%**	**+6%**
Residential	262.8	255.4	281.2	-3%	+7%
Commercial	167.0	162.3	178.6	-3%	+7%
Industrial	387.0	395.9	435.7	2%	+13%
Transportation	31.8	30.9	34.1	-3%	+7%
Electricity Generation	320.1	311.0	336.5	-3%	+5%
U.S. Territories	1.3	1.1	1.5	-12%	+17%
Petroleum[b]	**2,487.2**	**2,355.4**	**2,628.1**	**-5%**	**+6%**
Residential	95.0	90.1	99.5	-5%	+5%
Commercial	50.9	48.6	52.9	-5%	+4%
Industrial	330.9	283.9	387.0	-14%	+17%
Transportation	1,861.0	1,739.2	1,979.1	-7%	+6%
Electric Utilities	102.3	98.6	108.1	-4%	+6%
U.S. Territories	47.2	43.7	52.3	-7%	+11%
Total (excluding Geothermal)[b]	**5,750.8**	**5,656.3**	**6,060.1**	**-2%**	**+5%**
Geothermal	**0.4**	**NE**	**NE**	**NE**	**NE**
Total (including Geothermal)[b,c]	**5,751.2**	**5,656.3**	**6,060.1**	**-2%**	**+5%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The most significant change impacting fuel combustion estimates in the current inventory was updating the C oxidation factor for all fuel types to 100 percent. This change was made according to IPCC (2006) and impacted emission estimates for all fuel types for all years.

An additional adjustment for silicon carbide used for petroleum coke manufacturing was added to the current Inventory as a source that is accounted for in the Industrial Processes chapter. This was reallocated to the industrial processes chapter, as the silicon carbide was consumed during non-energy related industrial activity.

The Energy Information Administration (EIA 2006b) updated energy consumption data for all years. These revisions primarily impacted the emission estimates for 2004. EIA (2006b) no longer reports a small amount of consumption of other liquids in the electricity generation sector, which represented a change from the previous inventory.

Overall, changes resulted in an average annual increase of 36.9 Tg CO_2 Eq. (0.7 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2004.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal coke (manufactured from coking coal). The non-energy applications are equally diverse, and include feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Municipal Solid Waste Combustion source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and these affect the mass of C in non-energy applications.

As shown in Table 3-11, fossil fuel emissions in 2005 from the non-energy uses of fossil fuels were 142.3 Tg CO_2 Eq., which constituted approximately 3 percent of overall fossil fuel emissions, approximately the same proportion as in 1990. In 2005, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,492 TBtu, an increase of 22 percent since 1990 (see Table 3-12). About 66.3 Tg of the C (243.1 Tg CO_2 Eq.) in these fuels was stored, while the remaining 38.8 Tg C (142.4 Tg CO_2 Eq.) was emitted. The proportion of C emitted as CO_2 has remained about constant since 1990, at about 36 to 40 percent of total non-energy consumption (see Table 3-11).

Table 3-11: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	1990	1995	2000	2001	2002	2003	2004	2005
Potential Emissions	312.8	346.7	385.5	364.9	368.4	356.4	396.6	385.5
C Stored	195.6	213.6	244.5	233.5	233.1	225.1	246.4	243.1
Emissions as a % of Potential	37%	38%	37%	36%	37%	37%	38%	37%
Emissions	**117.2**	**133.1**	**141.0**	**131.3**	**135.3**	**131.3**	**150.2**	**142.3**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2006) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-12 and Table 3-13 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[30] Consumption values were also adjusted to subtract exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor. For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Municipal Solid Waste Combustion source category, the storage factors do not account for losses at the disposal end of the life cycle. For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC/UNEP/OECD/IEA (1997), which in turn draws from Marland and Rotty (1984). For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-12: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	1995	2000	2001	2002	2003	2004	2005
Industry	**4,223.7**	**4,771.7**	**5,261.2**	**5,045.2**	**5,032.3**	**4,864.3**	**5,295.4**	**5,208.2**
Industrial Coking Coal	0.0	43.8	62.8	25.5	46.4	72.0	214.7	136.6
Industrial Other Coal	8.2	11.3	12.4	11.3	12.0	11.9	11.9	11.9
Natural Gas to Chemical Plants, Other Uses	278.4	330.3	421.3	408.6	364.6	348.8	340.2	365.8
Asphalt & Road Oil	1,170.2	1,178.2	1,275.7	1,256.9	1,240.0	1,219.5	1,303.9	1,323.2
LPG	1,119.1	1,484.7	1,604.6	1,539.0	1,565.4	1,437.7	1,435.9	1,441.6
Lubricants	186.3	177.8	189.9	174.0	171.9	159.0	161.0	160.2
Pentanes Plus	77.3	285.3	228.7	199.8	166.1	158.3	156.4	146.0
Naphtha (<401 ° F)	325.7	350.6	592.8	489.4	564.2	573.4	687.5	678.5
Other Oil (>401 ° F)	677.2	612.7	554.3	525.9	456.2	501.0	547.5	515.1
Still Gas	21.3	40.1	12.6	35.8	57.8	59.0	63.5	67.7
Petroleum Coke	81.0	44.1	47.8	128.1	110.2	79.3	169.8	145.0

[30] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

Special Naphtha	100.9	66.9	94.4	77.9	99.5	75.7	47.2	60.9
Distillate Fuel Oil	7.0	8.0	11.7	11.7	11.7	11.7	11.7	11.7
Waxes	33.3	40.6	33.1	36.3	32.2	31.0	30.8	31.4
Miscellaneous Products	137.8	97.1	119.2	124.9	134.2	126.0	113.4	112.8
Transportation	**176.0**	**167.9**	**179.4**	**164.3**	**162.4**	**150.1**	**152.1**	**151.3**
Lubricants	176.0	167.9	179.4	164.3	162.4	150.1	152.1	151.3
U.S. Territories	**86.7**	**90.8**	**165.5**	**80.3**	**138.6**	**127.9**	**136.6**	**132.2**
Lubricants	0.7	2.0	16.4	0.0	1.5	9.3	10.0	9.6
Other Petroleum (Misc. Prod.)	86.0	88.8	149.1	80.3	137.2	118.6	126.6	122.6
Total	**4,486.4**	**5,030.5**	**5,606.1**	**5,289.8**	**5,333.3**	**5,142.4**	**5,584.1**	**5,491.7**

+ Does not exceed 0.05 TBtu

Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.

Note: Totals may not sum due to independent rounding.

Table 3-13: 2005 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2 Eq.)
Industry	**5,208.2**	**99.4**	**-**	**65.8**	**33.7**	**123.4**
Industrial Coking Coal	136.6	4.2	0.10	0.4	3.8	14.0
Industrial Other Coal	11.9	0.3	0.61	0.2	0.1	0.4
Natural Gas to Chemical Plants	365.8	5.3	0.61	3.2	2.0	7.5
Asphalt & Road Oil	1,323.2	27.3	1.00	27.3	0.0	0.0
LPG	1,441.6	24.2	0.61	14.9	9.4	34.3
Lubricants	160.2	3.2	0.09	0.3	2.9	10.8
Pentanes Plus	146.0	2.7	0.61	1.6	1.0	3.8
Naphtha (<401° F)	678.5	12.3	0.61	7.6	4.8	17.4
Other Oil (>401° F)	515.1	10.3	0.61	6.3	4.0	14.6
Still Gas	67.7	1.2	0.61	0.7	0.5	1.7
Petroleum Coke	145.0	4.0	0.50	2.0	2.0	7.4
Special Naphtha	60.9	1.2	0.61	0.7	0.5	1.7
Distillate Fuel Oil	11.7	0.2	0.50	0.1	0.1	0.4
Waxes	31.4	0.6	0.58	0.4	0.3	1.0
Miscellaneous Products	112.8	2.3	0.00	0.0	2.3	8.4
Transportation	**151.3**	**3.1**	**-**	**0.3**	**2.8**	**10.2**
Lubricants	151.3	3.1	0.09	0.3	2.8	10.2
U.S. Territories	**132.2**	**2.6**	**-**	**0.3**	**2.4**	**8.7**
Lubricants	9.6	0.2	0.09	0.0	0.2	0.6
Other Petroleum (Misc. Prod.)	122.6	2.5	0.10	0.2	2.21	8.1
Total	**5,491.7**	**105.1**		**66.3**	**38.8**	**142.3**

+ Does not exceed 0.05 TBtu

- Not applicable.

[a] To avoid double counting, exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-11). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including volatile organic compound, solvent, and non-combustion CO emissions, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and energy recovery. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 1995, 2001), *National Air Quality and Emissions Trends Report* (EPA 2006a), *Toxics Release Inventory, 1998* (2000a), *Biennial Reporting System* (EPA 2004a, 2006b), and pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004b); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005); the National Petrochemical & Refiners Association (NPRA 2001); the National Asphalt Pavement Association (Connolly 2000); the Emissions Inventory Improvement Program (EIIP 1998, 1999); the U.S. Census Bureau (1999, 2003, 2004); the American Plastics Council (APC 2000, 2001, 2003, 2005, 2006; Eldredge-Roebuck 2000); the Society of the Plastics Industry (SPI 2000); Bank of Canada (2006); Financial Planning Association (2006); INEGI (2006); Statistics Canada (2006); the United States International Trade Commission (2006); the Pesticide Action Network (PAN 2002); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2002, 2006; STMC 2003); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001, 2003, 2005, 2006); the *Material Safety Data Sheets* (Miller 1999); the Chemical Manufacturer's Association (CMA 1999); and the American Chemistry Council (ACC 2005, 2006.) Specific data sources are listed in full detail in Annex 2.3.

Uncertainty

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-14 (emissions) and Table 3-15 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2005 was estimated to be between 113.1 and 153.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 8 percent above the 2005 emission estimate of 142.3 Tg CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-14: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	81.9	65.4	98.1	-20%	+20%
Asphalt	CO_2	0.0	0.2	0.7	NA	NA
Lubricants	CO_2	21.6	17.9	25.0	-17%	+16%

Waxes	CO_2	1.0	0.7	1.5	-25%	+55%
Other	CO_2	37.9	17.4	40.1	-54%	+6%
Total	**CO_2**	**142.3**	**113.1**	**153.7**	**-21%**	**+8%**

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

Table 3-15: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2005 Storage Factor (%)	Uncertainty Range Relative to Inventory Factor[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	61%	59%	63%	-4%	+3%
Asphalt	CO_2	100%	99%	100%	-1%	+0%
Lubricants	CO_2	9%	4%	18%	-57%	+90%
Waxes	CO_2	58%	44%	69%	-25%	+20%
Other	CO_2	22%	20%	64%	-10%	+189%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-15, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

Recalculations Discussion

The methodology of the current Inventory reflects three corrections and two minor changes. Plastics data from the American Plastics Council includes some Mexican and Canadian production in addition to U.S. production. In the previous inventory, the plastics geography correction was not correctly accounting for Mexican and Canadian production from 2002 through 2004. This correction caused an increase in the quantity of C emitted by 0.64 Tg C, 0.98 Tg C, and 1.02 Tg C compared to the previously reported estimates for 2002 though 2004.

As noted earlier, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived

CO_2 emissions accounted for in the Industrial Processes chapter. For the current inventory, for the first time, silicon carbide production is reported as a specific industrial process. To avoid double-counting of C emissions in the NEU section and the Industrial Processes chapter, the quantity of petroleum coke used as an input to silicon carbide was deducted from the potential emissions covered in this chapter.

In addition, in the previous inventory, the cleanser consumption data was not properly accounting for data over the whole time series. The update in the current Inventory resulted in an increase in exports throughout the time series and decreased C emissions across the time series. Also, in the uncertainty analysis, Industrial Other Coal was previously being counting as an Other rather than a Feedstock. The calculations presented are now correctly accounting for Industrial Other Coal.

Additionally, the oxidation factor for MECS data was increased from 99 percent to 100 percent to be consistent throughout the Energy and Industrial Processes chapters. This change caused an increase in the quantity of C emitted by 0.10 to 0.20 Tg C compared to the previous Inventory.

Planned Improvements

There are several improvements planned for the future:

- Updating the analysis to comply with IPCC (2006). These changes will affect both the non-energy use and industrial processes sections.
- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional "fates" may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for the remaining fuels (petroleum coke, miscellaneous products, and other petroleum). Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3.

3.3. Stationary Combustion (excluding CO_2) (IPCC Source Category 1A)

Stationary combustion encompasses all fuel combustion activities from fixed sources (versus mobile combustion). Other than CO_2, which was addressed in the previous section, gases from stationary combustion include the greenhouse gases CH_4 and N_2O and the indirect greenhouse gases NO_x, CO, and NMVOCs.[31] Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, and ambient environmental conditions. Emissions also vary with operation and maintenance practices.

N_2O and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up, shutdown and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). CH_4 and NMVOC emissions from stationary combustion are primarily a

[31] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

function of the CH_4 and NMVOC content of the fuel and combustion efficiency.

Emissions of CH_4 decreased 13 percent overall since 1990 to 6.9 Tg CO_2 Eq. (330 Gg) in 2005. This decrease in CH_4 emissions was primarily due to lower wood consumption in the residential sector. Conversely, N_2O emissions rose 12 percent since 1990 to 13.8 Tg CO_2 Eq. (45 Gg) in 2005. The largest source of N_2O emissions was coal combustion by electricity generators, which alone accounted for 65 percent of total N_2O emissions from stationary combustion in 2005. Overall, however, stationary combustion is a small source of CH_4 and N_2O in the United States.

Table 3-16: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005
Electric Power	**0.6**	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	+	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	**2.1**	**2.3**	**2.3**	**2.1**	**2.0**	**2.0**	**2.1**	**1.9**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.7
Wood	0.9	1.0	1.0	0.9	0.8	0.8	0.9	0.7
Commercial	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.1
Natural gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Residential	**4.4**	**4.0**	**3.5**	**3.1**	**3.1**	**3.3**	**3.4**	**3.4**
Coal	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wood	3.5	3.1	2.6	2.2	2.3	2.4	2.5	2.5
U.S. Territories	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**8.0**	**7.8**	**7.4**	**6.8**	**6.8**	**7.0**	**7.1**	**6.9**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-17: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005
Electric Power	**7.6**	**8.0**	**9.3**	**9.1**	**9.1**	**9.4**	**9.4**	**9.6**
Coal	7.1	7.6	8.8	8.5	8.6	8.8	8.8	9.0
Fuel Oil	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2
Industrial	**3.2**	**3.3**	**3.3**	**3.1**	**3.0**	**2.9**	**3.1**	**2.8**
Coal	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6
Fuel Oil	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Natural Gas	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Wood	1.7	1.9	1.9	1.7	1.6	1.6	1.7	1.5
Commercial	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.4**	**0.4**	**0.3**
Coal	0.1	0.1	+	+	+	+	+	+

Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**1.0**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1
Wood	0.7	0.6	0.5	0.4	0.4	0.5	0.5	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**12.3**	**12.8**	**14.0**	**13.5**	**13.4**	**13.7**	**13.9**	**13.8**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 3-18: CH_4 Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005
Electric Power	**27**	**27**	**33**	**32**	**32**	**34**	**34**	**35**
Coal	16	18	20	20	20	20	20	21
Fuel Oil	4	2	3	4	3	4	4	4
Natural Gas	3	4	5	5	5	5	5	6
Wood	4	4	4	4	4	5	5	5
Industrial	**101**	**110**	**108**	**99**	**97**	**96**	**99**	**89**
Coal	16	15	14	14	13	13	14	13
Fuel Oil	6	5	5	6	5	6	6	6
Natural Gas	37	42	42	38	39	38	38	35
Wood	41	47	47	41	40	39	42	35
Commercial	**42**	**43**	**44**	**42**	**42**	**44**	**44**	**43**
Coal	1	1	1	1	1	1	1	1
Fuel Oil	9	7	7	7	6	7	8	7
Natural Gas	13	15	16	15	15	16	15	15
Wood	19	21	20	19	20	20	20	20
Residential	**210**	**190**	**165**	**147**	**150**	**158**	**160**	**160**
Coal	9	5	3	4	4	4	4	3
Fuel Oil	14	13	15	15	14	15	15	14
Natural Gas	21	24	24	23	24	25	24	24
Wood	165	148	122	105	108	114	117	120
U.S. Territories	**2**	**2**	**2**	**3**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	2	2	2	3	3	3	3	3
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**382**	**373**	**351**	**324**	**324**	**334**	**340**	**330**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.

Table 3-19: N_2O Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005
Electricity Generation	**24**	**26**	**30**	**29**	**29**	**30**	**30**	**31**
Coal	23	25	28	28	28	28	28	29
Fuel Oil	1	+	1	1	1	1	1	1
Natural Gas	+	+	1	1	1	+	1	1

Wood	+	+	1	+	1	1	1	1
Industrial	**10**	**11**	**11**	**10**	**10**	**9**	**10**	**9**
Coal	2	2	2	2	2	2	2	2
Fuel Oil	2	1	2	2	2	2	2	2
Natural Gas	1	1	1	1	1	1	1	1
Wood	5	6	6	5	5	5	6	5
Commercial	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	1	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Residential	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1	1
Natural Gas	+	+	+	+	+	+	+	+
Wood	2	2	2	1	1	2	2	2
U.S. Territories	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Total	**40**	**41**	**45**	**44**	**43**	**44**	**45**	**45**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

CH_4 and N_2O emissions were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electric power, and U.S. territories. For the CH_4 and N_2O estimates, fuel consumption data for coal, natural gas, fuel oil for the United States were obtained from EIA's *Monthly Energy Review* and unpublished supplemental tables on petroleum product detail (EIA 2006a). Wood consumption data for the United States was obtained from EIA's *Annual Energy Review* (EIA 2006b). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Grillot (2006).[32] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[33] Construction and agricultural fuel use was obtained from EPA (2004). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA.

Emission factors for the four end-use sectors were provided by the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

More detailed information on the methodology for calculating emissions from stationary combustion, including

[32] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[33] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

emission factors and activity data, is provided in Annex 3.1.

Uncertainty

CH_4 emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. A total of 115 input variables were simulated for the uncertainty analysis of this source category (85 from the CO_2 emissions from fossil fuel combustion inventory estimation model and 30 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[34] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[35] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-20. Stationary combustion CH_4 emissions in 2005 (*including* biomass) were estimated to be between 4.8 and 14.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 30 percent below to 112 percent above the 2005 emission estimate of 6.9 Tg CO_2 Eq.[36] Stationary combustion N_2O emissions in 2005 (*including* biomass) were estimated to be between 10.8 and 39.9 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 22 percent below to 189 percent above the 2005 emissions estimate of 13.8 Tg CO_2 Eq.

Table 3-20: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	6.9	4.8	14.7	-30%	+112%
Stationary Combustion	N_2O	13.8	10.8	39.9	-22%	+189%

[34] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[35] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[36] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to several changes. Slight changes to emission estimates for sectors are due to revised data from EIA (2006a). This revision is explained in greater detail in the section on CO_2 Emissions from Fossil Fuel Combustion within this sector. Wood consumption data from EIA (2006b) were revised for the commercial/institutional and residential sectors. The combination of the methodological and historical data changes resulted in an average annual increase of 0.2 Tg CO_2 Eq. (2.0 percent) in CH_4 emissions from stationary combustion and an average annual increase of 0.1 Tg CO_2 Eq. (0.2 percent) in N_2O emissions from stationary combustion for the period 1990 through 2004.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

3.4. Mobile Combustion (excluding CO_2) (IPCC Source Category 1A)

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, as well as indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. CH_4 and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

Emissions from mobile combustion were estimated by transport mode (e.g., highway, air, rail), fuel type (e.g. motor gasoline, diesel fuel, jet fuel), and vehicle type (e.g. passenger cars, light-duty trucks). Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile combustion emissions. Table 3-21 and Table 3-22 provide CH_4 and N_2O emission estimates- in Tg CO_2 Eq.; Table 3-23 and Table 3-24 present

these estimates in Gg of each gas.[37]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.5 percent) but was the second largest source of U.S. N_2O emissions (8 percent). From 1990 to 2005, mobile source CH_4 emissions declined by 45 percent, to 2.6 Tg CO_2 Eq. (125 Gg), due largely to control technologies employed on highway vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 13 percent, to 38.0 Tg CO_2 Eq. Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 31 percent decrease in mobile source N_2O emissions from 1998 to 2005. As a result, N_2O emissions in 2005 were 13 percent lower than in 1990, at 38.0 Tg CO_2 Eq. (123 Gg) (see Figure 3-17). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-17: Mobile Source CH_4 and N_2O Emissions

Table 3-21: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	1995	2000	2001	2002	2003	2004	2005
Gasoline Highway	**4.2**	**3.8**	**2.8**	**2.6**	**2.4**	**2.2**	**2.1**	**1.9**
Passenger Cars	2.6	2.1	1.6	1.5	1.4	1.2	1.2	1.1
Light-Duty Trucks	1.4	1.4	1.1	1.0	1.0	0.9	0.8	0.8
Heavy-Duty Vehicles	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	+	+	+	+	+	+	+	+
Alternative Fuel Highway	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Non-Highway	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Ships and Boats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Farm Equipment	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Construction Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other[b]	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**4.3**	**3.5**	**3.2**	**3.1**	**2.9**	**2.8**	**2.6**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

[a] See Annex 3.2 for definitions of highway vehicle types.

[b] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-22: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005
Gasoline Highway	**40.1**	**49.8**	**48.8**	**45.5**	**42.8**	**39.5**	**36.7**	**33.4**
Passenger Cars	25.4	26.9	24.7	23.2	21.9	20.3	18.8	17.0
Light-Duty Trucks	14.1	22.1	23.3	21.4	20.0	18.2	17.0	15.6
Heavy-Duty Vehicles	0.6	0.7	0.9	0.9	0.9	0.9	0.9	0.8
Motorcycles	+	+	+	+	+	+	+	+

[37] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2005.

Diesel Highway	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Highway	**3.4**	**3.6**	**4.0**	**3.8**	**3.9**	**3.9**	**4.0**	**4.1**
Ships and Boats	0.4	0.4	0.5	0.3	0.5	0.4	0.5	0.5
Locomotives	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Farm Equipment	1.7	1.7	1.9	1.8	1.7	1.7	1.7	1.8
Construction Equipment	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Aircraft	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Other*	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Total	**43.7**	**53.7**	**53.2**	**49.7**	**47.1**	**43.8**	**41.2**	**38.0**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

*"Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-23: CH_4 Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005
Gasoline Highway	**201**	**180**	**135**	**124**	**115**	**106**	**99**	**92**
Passenger Cars	125	101	76	70	65	59	56	51
Light-Duty Trucks	65	69	53	49	45	42	39	37
Heavy-Duty Vehicles	10	9	5	5	4	4	4	3
Motorcycles	1	1	1	1	1	1	1	1
Diesel Highway	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	1	1	1	1	1	1	1	1
Alternative Fuel Highway	**+**	**+**	**1**	**1**	**2**	**2**	**2**	**2**
Non-Highway	**24**	**26**	**28**	**27**	**28**	**28**	**29**	**30**
Ships and Boats	3	4	5	3	4	4	5	5
Locomotives	3	3	3	3	3	3	4	4
Farm Equipment	7	7	7	7	7	6	7	7
Construction Equipment	4	5	5	6	6	6	6	7
Aircraft	2	3	3	3	3	4	4	4
Other*	3	3	4	4	4	4	4	4
Total	**226**	**207**	**165**	**154**	**146**	**136**	**131**	**125**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table 3-24: N_2O Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005
Gasoline Highway	**129**	**161**	**158**	**147**	**138**	**127**	**118**	**108**
Passenger Cars	82	87	80	75	71	66	61	55
Light-Duty Trucks	45	71	75	69	65	59	55	50
Heavy-Duty Vehicles	2	2	3	3	3	3	3	3
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	1	1	1	1	1	1	1	1

Alternative Fuel Highway	+	+	+	+	+	+	+	+
Non-Highway	**11**	**12**	**13**	**12**	**13**	**12**	**13**	**13**
Ships and Boats	1	1	2	1	2	1	2	2
Locomotives	1	1	1	1	1	1	1	1
Farm Equipment	6	5	6	6	6	5	6	6
Construction Equipment	1	1	1	1	1	1	1	1
Aircraft	1	1	1	1	2	2	2	2
Other*	1	2	2	2	2	2	2	2
Total	**141**	**173**	**172**	**160**	**152**	**141**	**133**	**123**

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for highway (on-road) vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

EPA (2006c), EPA (2005) and EPA (2003) provide emission estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles,[38] aircraft, and seven categories of non-highway vehicles.[39] These emission estimates primarily reflect EPA data, which, in final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The methodology used to develop these estimates can be found on EPA's Air Pollutant Emission Trends website, at <http://www.epa.gov/ttn/chief/trends/index.html>.

Highway Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel highway vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Emission estimates from alternative fuel vehicles (AFVs)[40] are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel highway vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel highway vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of GHGs depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test

[38] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[39] These categories included: locomotives, marine vessels, farm equipment, construction equipment, other off-highway liquid fuel (e.g. recreational vehicles and lawn and garden equipment), and other off-highway gaseous fuel (e.g., other off-highway equipment running on compressed natural gas).

[40] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bifuel or dual fuel vehicles that may be partially powered by gasoline or diesel.

run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2 to approximate average driving characteristics.

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2005 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in *Highway Statistics* (FHWA 1996 through 2006). VMT was then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2006) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2006). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2006e) and EPA (2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

Control technology and standards data for highway vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2006a, 2006b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993), EPA (1994a), EPA (1994b), EPA (1998), EPA (1999a), and IPCC/UNEP/OECD/IEA (1997).

These emission estimates were obtained from preliminary data (EPA 2006c), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site.

Non-Highway Vehicles

To estimate emissions from non-highway vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[41] Activity data were obtained from AAR (2006), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DOE (1993 through 2006), DESC (2006), DOC (1991 through 2006), DOT (1991 through 2006), EIA (2006a), EIA (2006b), EIA (2004), EIA (2002), EIA (1991 through 2006), EPA (2006e), Esser (2003 through 2004), FAA (2006a and 2006b), Lou (2002), and Whorton (2006). Emission factors for non-highway modes were taken from IPCC/UNEP/OECD/IEA (1997).

Uncertainty

This section discusses the uncertainty of the emission estimates for CH_4 and N_2O. Uncertainty was analyzed separately for highway vehicles and non-highway vehicles due to differences in their characteristics and their contributions to total mobile source emissions.

A quantitative uncertainty analysis was conducted for the highway portion of the mobile source sector using the

[41] The consumption of international bunker fuels is not included in these activity data, but is estimated separately under the International Bunker Fuels source category.

IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, using @RISK software. The uncertainty analysis was performed on 2005 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following two major sets of input variables: (1) vehicle miles traveled (VMT) data, by vehicle and fuel type and (2) emission factor data, by vehicle, fuel, and control technology type.

The emission factors for highway vehicles used in the Inventory were obtained from ICF (2006b) and ICF (2004). These factors were based on laboratory testing of vehicles. While the controlled testing environment simulates real driving conditions, emission results from such testing can only approximate real world conditions and emissions. For some vehicle and control technology types, the testing did not yield statistically significant results within the 95 percent confidence interval, requiring expert judgment to be used in developing the emission factors. In those cases, the emission factors were developed based on comparisons of fuel consumption between similar vehicle and control technology categories.

The estimates of VMT for highway vehicles by vehicle type in the United States were provided by FHWA (1996 through 2006), and were generated through the cooperation of FHWA and state and local governments. While the uncertainty associated with total U.S. VMT is believed to be low, the uncertainty within individual source categories was assumed to be higher given uncertainties associated with apportioning total VMT into individual vehicle categories, by fuel type, by technology type, and equipment age.

A significant amount of uncertainty is associated with the emission estimates for non-road sources. A primary cause is a large degree of uncertainty regarding emission factors. The IPCC *Good Practice Guidance* reports that CH_4 emissions from aviation and marine sources may be uncertain by a factor of two, while N_2O emissions may be uncertain by an order of magnitude for marine sources and several orders of magnitude for aviation. No information is provided on the uncertainty of emission factors for other non-highway sources.

Fuel consumption data have a lower uncertainty than emission factors, though large uncertainties do exist for individual sources.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-25. Mobile combustion CH_4 emissions in 2005 were estimated to be between 2.5 and 2.8 Tg CO_2 Eq. at a 95 percent confidence level (or in 19 out of 20 Monte Carlo Simulations). This indicates a range of 6 percent below to 6 percent above the 2005 emission estimate of 2.6 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions in 2005 were estimated to be between 31.0 and 45.0 Tg CO_2 Eq., indicating a range of 18 percent below to 19 percent above the 2005 emission estimate of 38.0 Tg CO_2 Eq.

Table 3-25: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	2.6	2.5	2.8	-6%	+6%
Mobile Sources	N_2O	38.0	31.0	45.0	-18%	+19%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and

activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. A number of adjustments were made to the historical data used in calculating emissions in the current Inventory.

For highway sources, vehicle age distributions for 1999 to the present were revised based on new data obtained from EPA's MOVES model (EPA 2006e). Diesel fractions for light trucks and medium-heavy trucks for 1998 through 2003 were updated based on data obtained from the Transportation Energy Data Book (DOE 2006). The highway vehicle emissions estimation procedures now include a new gasoline vehicle emission control technology, Tier 2, and updated emissions factors for LEVs (ICF 2006b). These changes resulted in a reduction in gasoline highway vehicle emissions from 1996 onward, and most notably since 2002. In addition, revisions were made to both the light-duty and heavy-duty alternative fuel vehicle (AFV) emissions factors (ICF 2006a), which resulted in an increase in N_2O emissions and a decrease in CH_4 from AFVs. Lastly, VMT and fuel consumption estimates for non-highway vehicles were revised for 2004 based on updated data from FHWA's *Highway Statistics* (FHWA 1996 through 2006).

Several improvements and updates were also made in the calculation of emissions from non-road vehicles. Commercial aircraft energy consumption estimates now come from the Federal Aviation Administration's (FAA) System for Assessing Aviation's Global Emissions (SAGE) database (FAA 2006b), rather than from the Bureau of Transportation Statistics. This change increased estimates of fuel consumption and emissions attributed to commercial aircraft, but does not affect the total aircraft emissions figures, since the "Other Aviation" category was eliminated. Class II and III railroad diesel use estimates for 2002 and 2004 were obtained from the American Short Line and Regional Railroad Association (Whorton 2006), instead of the Upper Great Plains Institute. EPA's updated NONROAD model was used to recalculate fuel consumption for non-highway mobile sources.

As a result of these changes, average estimates of CH_4 and N_2O emissions from mobile combustion were slightly higher—showing an increase of no more than 0.32 Tg CO_2 Eq. (less than 0.6 percent) each year—for the period 1990 through 2000. In contrast, emissions estimates were lower in every year between 2001 and 2004, compared to last year's inventory. Specifically, estimates decreased 1.16 Tg CO_2 Eq. (2.4 percent) in 2003 and 1.83 Tg CO_2 Eq. (4 percent) in 2004.

Planned Improvements

While the data used for this report represent the most accurate information available, four areas have been identified that could potentially be improved in the short-term given available resources:

1) Improve estimation of VMT and fuel consumption by vehicle type (e.g., passenger car, light-duty truck, heavy-duty truck, bus): Potential improvements in the breakdown of VMT and fuel consumption by vehicle type could be developed based on further investigation of the methodologies and data sources used. Estimates of motor vehicle travel and fuel consumption by vehicle type are taken from FHWA's Highway Statistics (FHWA 1996 to 2006), which in turn are based on data from the Highway Performance Monitoring System, fuel tax receipts, Vehicle Inventory and Use Survey (VIUS), and other sources. FHWA annually updates only the most recent year of historical VMT and fuel consumption estimates (for instance, only the 2004 estimates in 2005 Highway Statistics are recalculated, while 1990–2003 remain constant). Additional data might help to develop improved estimates of historical VMT and fuel consumption by vehicle type going back through 1990. Moreover, the shares of VMT associated with each vehicle type reported by FHWA are quite different from estimates used in EPA's MOBILE model, and these differences should be investigated.

2) Improve the process of apportioning VMT by vehicle type to each fuel type: The current inventory process for estimating VMT by vehicle/fuel type category involves apportioning VMT by vehicle type to each fuel type on the basis of fuel consumption. While this is a reasonable simplification, this approach implicitly assumes the same average fuel economy for gasoline and diesel vehicles. A more accurate apportionment of VMT by fuel type for light-duty trucks and medium/heavy-duty trucks could potentially be developed using data on vehicle travel from the Vehicle Inventory and Use Survey (U.S. Census Bureau 2000) and other publications, or using VMT breakdowns by vehicle/fuel type combinations from the MOBILE6 or MOVES models.

3) Continue the Reconciliation of Fuel Consumption Estimates used for Calculating N_2O/CH_4 and CO_2: Estimates of transportation fuel consumption by fuel type from EIA are used as the basis for estimating CO_2 emissions from the transportation sector. These estimates are then apportioned to mode and vehicle category based on "bottom up" estimates of fuel consumption from sources such as FHWA's *Highway Statistics* (FHWA 1996 through 2006) and DOE's *Transportation Energy Data Book* (DOE 1993 through 2006). These sources are also used to develop N_2O and CH_4 estimates. The EPA fuel consumption estimates, however, differ from the estimates derived using "bottom up" sources. For this Inventory, estimates of distillate fuel consumption have been reconciled. Potential improvements include reconciling additional fuel consumption estimates from EIA and other data sources, and revising the current process of allocating CO_2 emissions to particular vehicle types.

4) Continue to examine ways to utilize EPA's MOVES model in the development of the Inventory estimates, including use for uncertainty analysis: Although the inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. The use of MOVES should be further explored.

3.5. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. All 115 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 24 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH_4 before, during, or after mining. In 2005, 13 coal mines collected CH_4 from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. In addition, one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. Two of the coal mines that sold gas to pipelines also used CH_4 to generate electricity or fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2005 were estimated to be 52.4 Tg CO_2 Eq. (2,494 Gg), a decline of 36 percent since 1990 (see Table 3-26 and Table 3-27). Of this amount, underground mines accounted for 68 percent, surface mines accounted for 17 percent, and post-mining emissions accounted for 15 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. CH_4 emissions increased slightly in 2003 due to additional gas drainage being vented to the atmosphere and a reduction in CH_4 recovery. Although overall emissions declined, recovery decreased again in 2005 with reduced production from pre-drainage wells, increased use of horizontal gob wells that are vented to the atmosphere, and temporary closure of a major project due to a mine fire. Surface mine emissions and post-mining emissions remained relatively constant from 1990 to 2005.

Table 3-26: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990	1995	2000	2001	2002	2003	2004	2005
Underground Mining	62.1	49.2	39.1	38.1	35.4	35.8	37.9	35.6
Liberated	67.6	61.6	53.9	54.5	52.7	51.3	53.9	50.6
Recovered & Used	(5.6)	(12.4)	(14.8)	(16.5)	(17.4)	(15.5)	(16.0)	(15.0)

Surface Mining	10.4	8.9	8.8	9.2	8.8	8.4	8.6	8.9
Post-Mining (Underground)	7.7	6.9	6.7	6.8	6.4	6.4	6.6	6.4
Post-Mining (Surface)	1.7	1.4	1.4	1.5	1.4	1.4	1.4	1.4
Total	**81.9**	**66.5**	**55.9**	**55.5**	**52.0**	**52.1**	**54.5**	**52.4**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-27: CH_4 Emissions from Coal Mining (Gg)

Activity	1990	1995	2000	2001	2002	2003	2004	2005
Underground Mining	2,955	2,343	1,860	1,812	1,684	1,707	1,803	1,696
Liberated	3,220	2,935	2,565	2,596	2,511	2,443	2,565	2,408
Recovered & Used	(265)	(592)	(704)	(784)	(827)	(736)	(762)	(712)
Surface Mining	497	425	417	438	420	402	411	425
Post-Mining (Underground)	367	328	317	323	304	305	315	305
Post-Mining (Surface)	81	69	68	71	68	65	67	69
Total	**3,899**	**3,165**	**2,662**	**2,644**	**2,476**	**2,480**	**2,597**	**2,494**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[42] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty-four mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2005, thirteen active coal mines sold recovered CH_4 into the local gas pipeline networks, while one coal mine used recovered CH_4 on site. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by

[42] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

multiplying basin-specific coal production, obtained from the Energy Information Administration's *Annual Coal Report* (see Table 3-28) (EIA 2006), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average *in situ* CH_4 content of the coal. Revised data on *in situ* CH_4 content and emissions factors are taken from EPA (1996) and AAPG (1984). This calculation accounts for CH_4 released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average *in situ* CH_4 content of coals mined in the basin.

Table 3-28: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,250	546,818	931,068
1995	359,477	577,638	937,115
2000	338,173	635,592	973,765
2001	345,305	676,142	1,021,446
2002	324,219	667,619	991,838
2003	320,047	651,251	971,297
2004	333,449	674,551	1,008,000
2005	334,404	691,460	1,025,864

Uncertainty

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 liberated and recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may increase if the drainage area is found to be larger than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-29. Coal mining CH_4 emissions in 2005 were estimated to be between 49.8 and 58.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 5 percent below to 12 percent above the 2005 emission estimate of 52.4 Tg CO_2 Eq.

Table 3-29: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	52.4	49.8	58.7	-5%	+12%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

In 2005, recalculations of emissions avoided at three Jim Walter Resources (JWR) coal mines in Alabama were performed because the mining company provided mine maps describing mined-out areas for each month from 2000 through 2005. In previous inventories, emissions avoided calculations for any pre-drainage wells at JWR coal mines were based on publicly-available data records from the Alabama State Oil & Gas Board. Also in previous inventories, emission reductions were calculated for pre-drainage wells that were located inside the mine plan boundaries and were declared "shut-in" by the O&G Board. In recent years, JWR had mined-through numerous pre-drainage wells that were subsequently converted to gob wells for further coal mine degasification. Because they were never shut in, emissions avoided were not calculated.

The mine maps provided by JWR allowed for a more accurate accounting as to when and which pre-drainage wells should be included in the emissions avoided calculations. As a result, recalculations were performed on years 2000 through 2004. The most pronounced changes to the inventory were made in the years 2003 through 2004, where corrections led to an overall reduction of emissions in 2003 and 2004 by 2.7 and 1.8 Tg CO_2 Eq., respectively. Minor changes were made to JWR emissions avoided for 1995 through 1996 as well.

For the current inventory, recalculations were performed on all years with negligible changes in 1994, 1996, and 1998 through 2002, as QA/QC of databases uncovered that emissions avoided had been miscalculated. Some recalculations were done in 2003 on Alabama mines but were not linked retroactively. These recalculations either led to no change in net emissions, or a change of 0.1 Tg CO_2 Eq. Emissions avoided for 2003 were adjusted downward as a major operator reported in 2004 that double-counting of some pre-drainage wells had previously occurred. Correction of this error led to a reduction in emissions avoided of 1.0 Tg CO_2 Eq., which contributed to the reduction in emissions in 2003 from 54.8 to 52.1 Tg CO_2 Eq.

3.6. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

All underground and surface coal mining liberates CH_4 as part of the normal mining operations. The amount of CH_4 liberated depends on the amount that resides in the coal ("*in situ*") and surrounding strata when mining occurs. The in-situ CH_4 content depends upon the amount of CH_4 created during the coal formation (i.e., coalification) process, and the geologic characteristics of the coal seams. During coalification, more deeply buried deposits tend to generate more CH_4 and retain more of the gas after uplift to minable depths. Deep underground coal seams generally have higher CH_4 contents than shallow coal seams or surface deposits.

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH_4 flow capacity of the mine;
- Mine flooding;

- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2005, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Abandoned mine emissions peaked in 1996 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2005, with only two closures in 2005. By 2005, abandoned mine emissions declined to 5.5 Tg CO_2 Eq. (see Table 3-30 and Table 3-31).

Table 3-30: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	1990	1995	2000	2001	2002	2003	2004	2005
Abandoned Underground Mines	6.0	8.9	8.8	8.1	7.7	7.5	7.3	7.0
Recovered & Used	0.0	0.7	1.5	1.5	1.6	1.5	1.5	1.4
Total	**6.0**	**8.2**	**7.3**	**6.7**	**6.1**	**5.9**	**5.8**	**5.5**

Note: Totals may not sum due to independent rounding.

Table 3-31: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	1990	1995	2000	2001	2002	2003	2004	2005
Abandoned Underground Mines	287	422	421	387	367	354	345	331
Recovered & Used	0	32	72	70	75	72	70	68
Total	**286**	**391**	**349**	**318**	**292**	**282**	**275**	**263**

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, P_r, declines as described by the isotherm. The emission rate declines because the mine pressure (P_w) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i(1+bD_it)^{(-1/b)}$$

where,

q = Gas rate at time t in mcf/d
q_i = Initial gas rate at time zero (t_o) in million cubic feet per day (mcfd)

b = The hyperbolic exponent, dimensionless
D_i = Initial decline rate, 1/yr
t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves are also affected by both sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_i e^{(-Dt)}$$

where,

q = Gas flow rate at time t in mcf/d
q_i = Initial gas flow rate at time zero (t_o) in mcfd
D = Decline rate, 1/yr
t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 − initial emissions from sealed mine / emission rate at abandonment prior to sealing). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 440 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 264 of the 440 mines (or 60 percent) is known to be either 1) vented to the atmosphere, 2) sealed to some degree (either earthen or concrete seals), or 3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 40 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, throughout the 20th century. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emissions rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to ventilation data for the total CH_4 liberation rate for fourteen mines that closed between 1992 and 2005. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions. From 1993 through 2005, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH_4 flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-32. Abandoned coal mines CH_4 emissions in 2005 were estimated to be between 4.6 and 6.5 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 16 percent below to 18 percent above the 2005 emission estimate of 5.5 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 40 percent of the mines), with a ±50 percent uncertainty.

Table 3-32: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	5.5	4.6	6.5	-16%	+18%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Quality assurance/quality control of the calculation spreadsheets for the 1990 through 2004 inventory years revealed an equation link that contained a minor error. The error was tracked back to the 1998 calculation worksheet and carried through 2004. The equation was corrected and the emissions recalculated for 1998 through 2004. In addition, a few other minor data corrections were completed during the recalculation process.

3.7. Natural Gas Systems (IPCC Source Category 1B2b)

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 111.1 Tg CO_2 Eq. (5,292 Gg) of CH_4 in 2005, an 11 percent decrease over 1990 emissions (see **Error! Reference source not found.** and **Error! Reference source not found.**), and 28.2 Tg CO_2 Eq. (28,185Gg) of non-energy CO_2 in 2005, a 16 percent decrease over 1990 emissions (see **Error! Reference source not found.**). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions.

CH_4 and non-energy CO_2 emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 and non-energy CO_2 emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-energy CO_2 emissions. Emissions from field production accounted for approximately 32 percent of CH_4 emissions and about 23 percent of non-energy CO_2 emissions from natural gas systems in 2005.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-energy CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 11 percent of CH_4 emissions and approximately 77 percent of non-energy CO_2 emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 34 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-energy CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,034,000 miles of distribution mains in 2005, an increase from just over 888,000 miles in 1990 (OPS 2006b). Distribution system emissions, which account for approximately 25 percent of CH_4 emissions

from natural gas systems and less than 1 percent of non-energy CO_2 emissions, result mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel).[43] An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2005 were 12 percent lower than 1990 levels.

Table 3-33. CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990	1995	2000	2001	2002	2003	2004	2005
Field Production	31.8	36.6	38.5	41.2	42.4	40.9	38.0	35.2
Processing	14.8	14.9	14.5	14.7	14.1	13.5	13.5	11.9
Transmission and Storage	46.8	46.3	44.1	41.0	42.5	42.3	40.6	36.8
Distribution	31.0	30.3	29.4	28.6	25.9	27.0	26.9	27.4
Total	**124.5**	**128.1**	**126.6**	**125.4**	**125.0**	**123.7**	**119.0**	**111.1**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-34. CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990	1995	2000	2001	2002	2003	2004	2005
Field Production	1,514	1,745	1,832	1,963	2,021	1,949	1,811	1,675
Processing	706	709	692	698	673	645	643	564
Transmission and Storage	2,230	2,205	2,102	1,950	2,025	2,013	1,934	1,751
Distribution	1,477	1,442	1,401	1,360	1,231	1,284	1,281	1,303
Total	**5,927**	**6,101**	**6,027**	**5,971**	**5,951**	**5,891**	**5,669**	**5,292**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-35. Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990	1995	2000	2001	2002	2003	2004	2005
Field Production	5.9	9.1	6.0	6.3	6.5	6.3	6.3	6.4
Processing	27.8	24.6	23.3	22.4	23.1	22.0	21.8	21.7
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+	+
Total	**33.7**	**33.8**	**29.4**	**28.8**	**29.6**	**28.4**	**28.2**	**28.2**

Note: Totals may not sum due to independent rounding.

Table 3-36. Non-energy CO_2 Emissions from Natural Gas Systems (Gg)

Stage	1990	1995	2000	2001	2002	2003	2004	2005
Field Production	5,876	9,083	5,955	6,307	6,462	6,341	6,309	6,350
Processing	27,752	24,621	23,333	22,387	23,066	22,002	21,780	21,736
Transmission and Storage	58	60	61	59	62	61	62	60
Distribution	43	42	41	40	40	40	40	39
Total	**33,729**	**33,807**	**29,390**	**28,793**	**29,630**	**28,445**	**28,190**	**28,185**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-energy-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80

[43] The percentages of total emissions from each stage may not sum to 100 percent due to independent rounding.

CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and non-energy CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-energy CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors. For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-energy CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); American Petroleum Institute (API 2005); Minerals and Management Service (MMS 2006a-e); Monthly Energy Review (EIA 2006e); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2006c,d,f); the Natural Gas STAR Program annual emissions savings (EPA 2006); Oil and Gas Journal (OGJ 1997–2006); Office of Pipeline Safety (OPS 2006a-b) and other Energy Information Administration publications (EIA 2004, 2006a,b,g); World Oil Magazine (2006a-b). Data for estimating emissions from hydrocarbon production tanks is incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2006) and the Alabama State Oil and Gas Board (Alabama 2006). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2006); Montana Board of Oil and Gas Conservation (Montana 2006); Oklahoma Geological Survey (Oklahoma 2006); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman (2003); New Mexico Oil Conservation Division (New Mexico 2006a,b); Texas Railroad Commission (Texas 2006a-d); Utah Division of Oil, Gas and Mining (Utah 2006). Emission factors were taken from EPA/GRI (1996). GRI's Unconventional Natural Gas and Gas Composition Databases (GRI 2001) were used to adapt the CH_4 emission factors into non-energy related CO_2 emission factors. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-energy CO_2 emission factors.

Uncertainty

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall.

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-37. Natural gas systems CH_4 emissions in 2005 were estimated to be between 82.2 and 144.4 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2005 were estimated to be between 20.8 and 36.6 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-37: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)	(%)

			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Natural Gas Systems	CH_4	111.1	82.2	144.4	-26%	+30%
Natural Gas Systems[b]	CO_2	28.2	20.8	36.6	-26%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.

Recalculations Discussion

Significant changes were made to the emission calculations in the Production sector. The first change implemented was to incorporate a variable CH_4 content of the natural gas produced in the United States to the emission factors of the production sector. In the past, CH_4 content for the emission factors was kept constant for each year and different National Energy Modeling System (NEMS) regions. For the revised method, the CH_4 content is first estimated in two base years, 1990 and 1995, using GRI and GTI data source estimates, respectively. Then the CH_4 content for other years in the time series 1990 through 2005 are driven by the natural gas production for each state and year. Each NEMS region's CH_4 content is calculated separately to reflect the differences in the reservoir basins around the country. The net effect of this restructuring on the historical emission estimates is an average 3 percent increase in emissions. The varying CH_4 content in each region added another source of uncertainty to the uncertainty analysis.

The second change to the production sector of the inventory was replacement of activity factors for five sources: separators, heaters, pneumatic devices, chemical injection pumps and compressors. The new activity factors were developed by re-organizing the original GRI activity factor data into the new NEMS production regions. The net effect of this change is a 2 percent decrease in 2004 emission estimates.

Another change in the estimates for the current Inventory is the accounting of CH_4 emission reductions from U.S. EPA National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations, which is the civil enforcement of the Maximum Achievable Control Technology or MACT standard. These federal regulations were enacted in 1999 and require a 95 percent reduction of emissions from dehydrator vents and condensate tanks with throughputs above the threshold levels set by the regulation. The inventory methodology now incorporates these emission reductions when describing the total emissions from natural gas systems. Overall, the net effect on the historical CH_4 emission estimates from this change is less than an average 1 percent decrease in emissions since 1999.

Finally, the inventory now contains estimates for non-energy related (vented, fugitive, flared) CO_2 emissions from the natural gas industry. The estimation uses the same activity and emission factors as the CH_4 emission estimates but adjusts the emission factors using the ratio of CO_2/CH_4 content of the natural gas. Efforts were made to ensure that there was no double-accounting of CO_2 emissions from other systems reported elsewhere in the U.S. Inventory.

The combination of these methodological and historical data changes resulted in an average annual decrease of 0.3 Tg CO_2 Eq. (0.3 percent) in CH_4 emissions from natural gas systems for the period 1990 through 2004.

Planned Improvements

One improvement being contemplated involves a trend analysis for the time series. As discussed above, the natural gas systems inventory now reflects changing emissions factors based on changing CH_4 content in natural gas in different NEMS regions. The uncertainty analysis, for the sake of simplicity, currently assumes a constant uncertainty across all years in the emissions time series. A trend analysis reflecting changing uncertainty in the time series will be conducted to more closely follow the IPCC Guidelines. Additional improvements include developing region specific emission and activity factors and incorporating any new data that becomes available from new studies in the future into the emissions model.

3.8. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Total CH_4 emissions from petroleum systems in 2005 were 28.5 Tg CO_2 Eq. (1,357 Gg). Since 1990, emissions have declined by 17 percent, due to a decline in domestic oil production and industry efforts to reduce emissions (see Table 3-38 and Table 3-39). The emission increase exhibited between 2004 and 2005 resulted from an increase in the number of offshore platforms (primarily shallow water, but also deep water). The various sources of emissions are detailed below.

Production Field Operations. Production field operations account for over 97 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 91 percent of the emissions from the production sector, fugitive emissions account for 3.5 percent, combustion emissions 5.3 percent, and process upset emissions, slightly over one-tenth of a percent. The most dominant sources of vented emissions are offshore oil platforms (shallow and deep water platforms), field storage tanks and natural-gas-powered pneumatic devices (low bleed and high bleed). These five sources alone emit over 86 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and combustion emissions from all equipment housed on the platform for both oil and associated gas on those labeled as oil platforms. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Two additional large sources, chemical injection pumps and gas engines, together account for nine percent of emissions from the production sector. The remaining five percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level, data on methane emissions in production field operations refer to Annex 3.5.

Crude Oil Transportation. Crude oil transportation activities account for less than one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 65 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 18 percent. The remaining 17 percent is distributed among seven additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly over two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented emissions account for about 87 percent of the emissions, while fugitive and combustion emissions account for approximately six and seven percent respectively. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Table 3-38: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	1995	2000	2001	2002	2003	2004	2005
Production Field Operations	**33.8**	**30.5**	**27.1**	**26.7**	**26.1**	**25.1**	**24.7**	**27.8**
Pneumatic device venting	10.3	9.7	9.0	8.9	8.9	8.7	8.6	8.5
Tank Venting	3.8	3.4	3.2	3.2	3.2	3.2	3.0	2.8
Combustion & process upsets	1.9	1.7	1.6	1.6	1.6	1.5	1.5	1.5
Misc. venting & fugitives	17.4	15.1	12.8	12.5	12.0	11.3	11.2	14.5
Wellhead fugitives	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Total	**34.4**	**31.1**	**27.8**	**27.4**	**26.8**	**25.8**	**25.4**	**28.5**

Note: Totals may not sum due to independent rounding.

Table 3-39: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2001	2002	2003	2004	2005
Production Field Operations	**1,609**	**1,450**	**1,292**	**1,271**	**1,242**	**1,196**	**1,176**	**1,324**
Pneumatic device venting	489	463	428	425	424	412	408	406
Tank Venting	179	161	154	154	151	150	142	133
Combustion & process upsets	88	82	76	75	75	73	72	72
Misc. venting & fugitives	827	719	612	594	570	540	533	692
Wellhead fugitives	26	25	22	22	23	22	21	21
Crude Oil Transportation	**7**	**6**	**5**	**5**	**5**	**5**	**5**	**5**
Refining	**25**	**25**	**28**	**27**	**27**	**27**	**28**	**28**
Total	**1,640**	**1,482**	**1,325**	**1,303**	**1,275**	**1,229**	**1,209**	**1,357**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1999, EPA 1996). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are very small compared to CH_4 emissions upstream of oil refineries.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999) and activity factors that are based on two EPA studies (1996, 1999). Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). The report provides emission factors and activity factors for all activities except those related to offshore oil production. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, MMS 2005c). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2005. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Minerals Management Service statistics (MMS 2005a,b,d).

Activity factors for years 1990 through 2005 were collected from a wide variety of statistical resources. For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2005 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. See Annex 3.5 for additional detail.

Nearly all emission factors were taken from EPA (1995, 1996, 1999). The remaining emission factors were taken from EPA default values in (EPA 2005) and the consensus of industry peer review panels.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2005, 1990 through 2006, 1995 through 2005, 1995 through 2006), *Methane Emissions from the Natural Gas Industry* by the Gas Research Institute and EPA (EPA & GRI 1996a-d), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), consensus of industry peer review panels, MMS reports (MMS 2001, 2005a,b,d), ICF analysis of MMS (EPA 2005, MMS 2005c), the *Oil & Gas Journal* (OGJ 2005–2006) and the United States Army Corps of Engineers (1995–2004).

Uncertainty

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison with a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of five major sources, which account for 86 percent of the total emissions, the uncertainty surrounding these five sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH_4 emissions in 2005 were estimated to be between 21.7 and 70.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 148 percent above the 2005 emission estimate of 28.5 Tg CO_2 Eq.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH_4	28.5	21.7	70.7	-24%	+148%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Two types of activity factor and activity driver revisions were made in the 2005 Petroleum Systems emissions inventory. Some revisions were due to a change in data sources referenced, while some revisions were due to updating previous years' data with revised data from existing data sources. Overall changes resulted in an annual decrease of approximately 0.14 Tg CO_2 Eq. (0.6 percent) for 2003 and 0.26 Tg CO_2 Eq. (1 percent) for 2004, relative to the previous inventory. For other years in the time series, the emission estimates increased by less than 0.1 percent.

Planned Improvements

A key improvement being contemplated is to include fugitive, vented, and combustion CO_2 emissions sources in the Petroleum Systems inventory.

[BEGIN BOX]

Box 3-3. Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2

reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Manufacture and Urea Application sections of the Inventory report, respectively.

IPCC (2006) includes, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. If site-specific monitoring and reporting data are not available, and the carbon capture and storage system cannot, therefore, be considered in a complete and consistent manner, the assumptions that the captured CO_2 is emitted. The assumption that, in the absence of site specific data, all CO_2 injected in storage sites is emitted is opposite from the current methodology implemented by the United States. The new methodology will not affect emission estimates for CO_2 consumption for non-EOR applications.

The United States initiated data collection efforts to incorporate this new methodology for the current Inventory report. However, time was not sufficient to fully implement this guidance and the estimates are not yet included in national totals. Preliminary estimates indicate that the amount of CO_2 emitted from EOR operations and pipelines is 35.2 Tg CO_2 (35,156 Gg CO_2) (see Table 3-41). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available. Therefore, these estimates assume all CO_2 is emitted. The United States is initiating a process to collect the necessary data to fully implement the 2006 IPCC Guidelines methodology for this source category in subsequent inventory reports.

Table 3-41: Emissions of CO_2 from EOR Operations and Pipelines (Tg CO_2 Eq.)

Year	1990	1995	2000	2001	2002	2003	2004	2005
Acid Gas Removal Plants	4.8	3.7	2.3	2.9	2.9	3.0	3.7	6.0
Naturally Occurring CO_2	20.8	22.7	22.7	23.0	21.9	24.3	27.1	28.5
Ammonia Production Plants	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Pipelines Transporting CO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**25.6**	**27.0**	**25.6**	**26.6**	**25.5**	**28.0**	**31.5**	**35.2**

Table 3-42: Emissions of CO_2 from EOR Operations and Pipelines (Gg)

Year	1990	1995	2000	2001	2002	2003	2004	2005
Acid Gas Removal Plants	4,832	3,672	2,264	2,894	2,943	2,993	3,719	5,992
Naturally Occurring CO_2	20,752	22,687	22,649	23,015	21,854	24,273	27,085	28,481
Ammonia Production Plants	0	676	676	676	676	676	676	676
Pipelines Transporting CO_2	8	8	8	8	8	8	7	7
Total	**25,592**	**27,044**	**25,598**	**26,593**	**25,482**	**27,951**	**31,489**	**35,156**

[END BOX]

3.9. Municipal Solid Waste Combustion (IPCC Source Category 1A5)

Combustion is used to manage about 7 to 17 percent of the municipal solid wastes (MSW) generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste

(EPA 2000b, Goldstein and Matdes 2001, Kaufman et al. 2004a, Simmons et al. 2006). Almost all combustion of MSW in the United States occurs at waste-to-energy facilities where useful energy is recovered, and thus emissions from waste combustion are accounted for in the Energy chapter. Combustion of municipal solid wastes results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste combustion are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in municipal solid wastes are predominantly from clothing and home furnishings. Tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the municipal solid waste combustion estimate, though waste disposal practices for tires differ from the rest of municipal solid waste (viz., most combustion occurs outside of MSW combustion facilities).

Approximately 34 million metric tons of municipal solid wastes were combusted in the United States in 2005 (Simmons et al. 2006). CO_2 emissions from combustion of municipal solid wastes rose 91 percent since 1990, to an estimated 20.9 Tg CO_2 Eq. (20,912 Gg) in 2005, as the volume of plastics and other fossil C-containing materials in MSW increased (see Table 3-43 and Table 3-44). Waste combustion is also a source of N_2O emissions (De Soete 1993). N_2O emissions from municipal solid waste combustion were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2005, and have not changed significantly since 1990.

Table 3-43: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Tg CO_2 Eq.)

Gas/Waste Product	1990	1995	2000	2001	2002	2003	2004	2005
CO_2	**10.9**	**15.7**	**17.9**	**18.3**	**18.5**	**19.5**	**20.1**	**20.9**
Plastics	8.0	10.3	12.1	12.4	12.4	13.0	13.4	13.9
Synthetic Rubber in Tires	0.2	0.8	0.9	0.9	1.0	1.0	1.1	1.2
Carbon Black in Tires	0.2	1.1	1.2	1.2	1.2	1.3	1.4	1.6
Synthetic Rubber in MSW	1.3	1.6	1.7	1.8	1.8	1.9	1.9	1.9
Synthetic Fibers	1.2	1.8	2.1	2.1	2.2	2.3	2.3	2.4
N_2O	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**11.4**	**16.2**	**18.3**	**18.7**	**18.9**	**19.9**	**20.5**	**21.3**

Table 3-44: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Gg)

Gas/Waste Product	1990	1995	2000	2001	2002	2003	2004	2005
CO_2	**10,950**	**15,712**	**17,889**	**18,344**	**18,513**	**19,490**	**20,115**	**20,912**
Plastics	7,976	10,347	12,068	12,378	12,365	12,984	13,381	13,852
Synthetic Rubber in Tires	191	841	893	895	952	1,010	1,108	1,207
Carbon Black in Tires	249	1,099	1,167	1,170	1,245	1,320	1,449	1,579
Synthetic Rubber in MSW	1,334	1,596	1,678	1,762	1,767	1,862	1,875	1,899
Synthetic Fibers	1,200	1,830	2,083	2,139	2,184	2,315	2,302	2,375
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**

Methodology

Emissions of CO_2 from MSW combustion include CO_2 generated by the combustion of plastics, synthetic fibers, and synthetic rubber, as well as the combustion of synthetic rubber and carbon black in tires. These emissions were estimated by multiplying the amount of each material combusted by the C content of the material and the fraction oxidized (98 percent). Plastics combusted in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and

synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the number of scrap tires used for fuel and the synthetic rubber and carbon black content of the tires.

More detail on the methodology for calculating emissions from each of these waste combustion sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from municipal solid waste combustion, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of material in municipal solid wastes and its portion combusted were taken from the *Characterization of Municipal Solid Waste in the United States* (EPA 2000b, 2002, 2003, 2005a, 2006b) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For synthetic rubber and carbon black in scrap tires, information was obtained from *U.S. Scrap Tire Markets in the United States 2005 Edition* (RMA 2006) and *Scrap Tires, Facts and Figures* (STMC 2000, 2001, 2002, 2003, 2006).

Average C contents for the "Other" plastics category, synthetic rubber in municipal solid wastes, and synthetic fibers were calculated from 1998 production statistics, which divide their respective markets by chemical compound. Information about scrap tire composition was taken from the Scrap Tire Management Council's internet site (STMC 2006).

The assumption that 98 percent of organic C is oxidized (which applies to all municipal solid waste combustion categories for CO_2 emissions) was reported in the EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006a).

Combustion of municipal solid waste also results in emissions of N_2O. These emissions were calculated as a function of the total estimated mass of municipal solid waste combusted and an emission factor. The N_2O emission estimates are based on different data sources. As noted above, N_2O emissions are a function of total waste combusted in each year; for 1990 through 2005, these data were derived from the information published in *BioCycle* (Simmons et al. 2006). Data on total waste combusted was not available for 2005, so the value for 2005 was assumed to equal the most recent value available (2004). Table 3-45 provides data on municipal solid waste generation and percentage combustion for the total waste stream. The emission factor of N_2O emissions per quantity of municipal solid waste combusted is an average of values from IPCC's *Good Practice Guidance* (2000).

Table 3-45: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted

Year	Waste Generation	Combusted (%)
1990	266,365,714	11.5
1995	296,390,405	10.0
2000	371,071,109	7.0
2001	353,086,962[a]	7.4[a]
2002	335,102,816	7.7
2003	343,482,645[b]	7.6[b]
2004	351,862,474	7.4
2005	351,862,474[c]	7.4[c]

[a] Interpolated between 2000 and 2002 values.
[b] Interpolated between 2002 and 2004 values.
[c] Assumed equal to 2004 value.

Uncertainty

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from municipal solid waste combustion. IPCC Tier 2 analysis allows the

specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the *Municipal Solid Waste in the United States* reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste combustion emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW combustion rate; fraction oxidized; missing data on MSW composition; average C content of MSW components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-46. Municipal solid waste combustion CO_2 emissions in 2005 were estimated to be between 15.5 and 25.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 26 percent below to 19 percent above the 2005 emission estimate of 20.9 Tg CO_2 Eq. Also at a 95 percent confidence level, municipal solid waste combustion N_2O emissions in 2005 were estimated to be between 0.11 and 1.02 Tg CO_2 Eq. This indicates a range of 74 percent below to 153 percent above the 2005 emission estimate of 0.40 Tg CO_2 Eq.

Table 3-46: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from Municipal Solid Waste Combustion (Tg CO_2 Eq. and Percent)

Source	Gas	2005 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Municipal Solid Waste Combustion	CO_2	20.9	15.5	25.0	-26%	+19%
Municipal Solid Waste Combustion	N_2O	0.4	0.11	1.02	-74%	+153%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

QA/QC and Verification

A source-specific QA/QC plan for was implemented for MSW Combustion. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from MSW combustion. Trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

Planned Improvements

EPA will investigate additional data sources for calculating an N_2O emission factor for U.S. MSW combustion.

3.10. Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2005 are reported in Table 3-47.

Table 3-47: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005
NO_x	**21,024**	**20,631**	**18,537**	**17,714**	**17,569**	**16,753**	**15,886**	**15,385**
Mobile Combustion	10,920	10,622	10,310	9,819	10,319	9,911	9,520	9,145
Stationary Combustion	9,883	9,821	8,002	7,667	6,837	6,428	5,952	5,824
Oil and Gas Activities	139	100	111	113	316	317	317	318
Municipal Solid Waste Combustion	82	88	114	114	97	98	98	98
*International Bunker Fuels**	*1,985*	*1,540*	*1,334*	*1,266*	*988*	*900*	*1,179*	*1,155*
CO	**125,759**	**104,527**	**89,835**	**86,167**	**84,369**	**81,832**	**79,435**	**77,173**
Mobile Combustion	119,480	97,755	83,680	79,972	77,382	74,756	72,269	69,915
Stationary Combustion	5,000	5,383	4,340	4,377	5,224	5,292	5,361	5,431
Municipal Solid Waste Combustion	978	1,073	1,670	1,672	1,440	1,457	1,475	1,493
Oil and Gas Activities	302	316	146	147	323	327	331	335
*International Bunker Fuels**	*115*	*113*	*124*	*120*	*118*	*112*	*124*	*122*
NMVOCs	**12,620**	**10,538**	**8,953**	**8,610**	**9,131**	**8,827**	**8,538**	**8,263**
Mobile Combustion	10,932	8,745	7,230	6,872	6,608	6,302	6,011	5,734
Stationary Combustion	912	973	1,077	1,080	1,733	1,734	1,735	1,736
Oil and Gas Activities	554	582	389	400	546	547	547	548
Municipal Solid Waste Combustion	222	237	257	258	244	244	244	245
*International Bunker Fuels**	*59*	*48*	*44*	*42*	*35*	*32*	*40*	*40*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2006), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's *Compilation of Air Pollutant Emission Factors, AP-42* (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

3.11. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are currently not included in national emission totals, but are reported separately

based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[44] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, as well as the 2006 IPCC GLs, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997).[45]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[46] Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[47]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2005 from the combustion of international bunker fuels from both aviation and marine activities were 98.2 Tg CO_2 Eq., or 14 percent below emissions in 1990 (see Table 3-48). Although emissions from international flights departing from the United States have increased significantly (34 percent), emissions from international shipping voyages departing the United States have decreased by 50 percent since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-48: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

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[44] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

[45] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[46] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

[47] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

Gas/Mode	1990	1995	2000	2001	2002	2003	2004	2005
CO_2	**113.7**	**100.6**	**101.1**	**97.6**	**89.1**	**83.7**	**97.2**	**97.2**
Aviation	45.7	50.2	59.9	58.7	61.1	58.8	62.2	62.6
Marine	68.0	50.4	41.3	38.9	28.0	24.9	34.9	34.6
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation	+	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.0**	**0.9**	**0.9**	**0.9**	**0.8**	**0.8**	**0.9**	**0.9**
Aviation	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Marine	0.5	0.4	0.3	0.3	0.2	0.2	0.3	0.3
Total	**114.8**	**101.6**	**102.2**	**98.6**	**90.0**	**84.5**	**98.2**	**98.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 3-49: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	1995	2000	2001	2002	2003	2004	2005
CO_2	**113,683**	**100,627**	**101,125**	**97,563**	**89,101**	**83,690**	**97,177**	**97,191**
Aviation	45,731	50,202	59,853	58,696	61,120	58,806	62,241	62,598
Marine	67,952	50,425	41,272	38,866	27,981	24,884	34,937	34,593
CH_4	**8**	**6**	**6**	**5**	**4**	**4**	**5**	**5**
Aviation	1	1	2	2	2	2	2	2
Marine	7	5	4	4	3	2	3	3
N_2O	**3**	**3**	**3**	**3**	**3**	**2**	**3**	**3**
Aviation	1	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1	1

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Methodology

Emissions of CO_2 were estimated by applying of C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2006) and USAF (1998), and heat content for jet fuel was taken from EIA (2006). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption were collected from three government agencies. Jet fuel consumed by U.S. flag air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT 1991 through 2006). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce

(BEA 1991 through 2006). Approximate average fuel prices paid by air carriers for aircraft on international flights was taken from DOT (1991 through 2006) and used to convert the BEA expenditure data to gallons of fuel consumed. Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2006). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-50. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2006). Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2006). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-51.

Table 3-50: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	1995	2000	2001	2002	2003	2004	2005
U.S. Carriers	1,954	2,221	2,737	2,619	2,495	2,418	2,465	2,760
Foreign Carriers	2,051	2,544	3,162	3,113	3,537	3,377	3,671	3,450
U.S. Military	862	581	480	524	482	473	498	462
Total	**4,867**	**5,347**	**6,380**	**6,255**	**6,515**	**6,268**	**6,634**	**6,673**

Note: Totals may not sum due to independent rounding.

Table 3-51: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005
Residual Fuel Oil	4,781	3,495	2,967	2,846	1,937	1,597	2,363	2,320
Distillate Diesel Fuel & Other	617	573	290	204	158	137	167	241
U.S. Military Naval Fuels	522	334	329	318	348	459	530	471
Total	**5,920**	**4,402**	**3,586**	**3,368**	**2,443**	**2,193**	**3,059**	**3,032**

Note: Totals may not sum due to independent rounding.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[48] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating

[48] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT (1991 through 2006) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As for the BEA (1991 through 2006) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[49]

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[50]

There is also concern as to the reliability of the existing DOC (1991 through 2006) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

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[49] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

[50] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Historical activity data for aviation was slightly revised for both U.S. and foreign carriers. These changes were due to revisions to international fuel cost for foreign carriers and international jet fuel consumption for U.S. carriers, provided by DOT (1991 through 2006). The density for jet fuel was also revised to reflect data obtained from Chevron (2000) and ASTM (1989). This revision increased the heat content for aviation jet fuel by 2 percent for all years. The C content coefficient was also revised from 0.99 to 1 for all fuel types based on guidance in IPCC (2006). These historical data changes resulted in changes to the emission estimates for 1990 through 2004, which averaged to an annual increase in emissions from international bunker fuels of 0.1 Tg CO_2 Eq. (0.1 percent) in CO_2 emissions, annual increase of less than 0.1 Tg CO_2 Eq. (less than 0.2 percent) in CH_4 emissions, and annual increase of less than 0.1 Tg CO_2 Eq. (0.2 percent) in N_2O emissions.

3.12. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates CO_2. However, in the long run the CO_2 emitted from biomass consumption does not increase atmospheric CO_2 concentrations, assuming that the biogenic C emitted is offset by the uptake of CO_2 that results from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net C fluxes from changes in biogenic C reservoirs in wooded or crop lands are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

In 2005, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 184.1 Tg CO_2 Eq. (184,067 Gg) (see Table 3-52 and Table 3-53). As the largest consumer of woody biomass, the industrial sector was responsible for 63 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-52: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1995	2000	2001	2002	2003	2004	2005
Industrial	135.3	155.1	153.6	135.4	131.1	128.0	138.5	116.2
Residential	59.8	53.6	44.3	38.2	39.2	41.2	42.3	43.3
Commercial	6.8	7.5	7.4	6.9	7.1	7.4	7.3	7.2
Electricity Generation	13.3	12.9	13.9	13.0	15.5	17.3	17.0	17.3
Total	**215.2**	**229.1**	**219.1**	**193.5**	**192.8**	**193.8**	**205.1**	**184.1**

Note: Totals may not sum due to independent rounding.

Table 3-53: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	1995	2000	2001	2002	2003	2004	2005
Industrial	135,348	155,075	153,559	135,415	131,079	127,970	138,522	116,238
Residential	59,808	53,621	44,340	38,153	39,184	41,247	42,278	43,309
Commercial	6,779	7,463	7,370	6,887	7,080	7,366	7,252	7,236
Electricity Generation	13,252	12,932	13,851	13,034	15,487	17,250	17,034	17,284
Total	**215,186**	**229,091**	**219,119**	**193,489**	**192,830**	**193,833**	**205,086**	**184,067**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States consisted primarily of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. These fuels burn cleaner than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

In 2005, the United States consumed an estimated 3.4 trillion Btu of ethanol, and as a result, produced approximately 22.4 Tg CO_2 Eq. (22,408 Gg) (see Table 3-54) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-54: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	4.2	4,155
1995	7.7	7,683
2000	9.2	9,188
2001	9.7	9,673
2002	11.5	11,520
2003	15.8	15,770
2004	19.7	19,740
2005	22.4	22,408

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2006) (see Table 3-55), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.953114 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.432359 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an EIA emission factor of 17.99 Tg C/QBtu (Lindstrom 2006) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2006) (see Table 3-56).

Table 3-55: Woody Biomass Consumption by Sector (Trillion Btu)

Year	Industrial	Residential	Commercial	Electricity Generation
1990	1,442	580	66	129
1995	1,652	520	72	125
2000	1,636	430	71	134
2001	1,443	370	67	126
2002	1,396	380	69	150
2003	1,363	400	71	167
2004	1,476	410	70	165
2005	1,238	420	70	168

Table 3-56: Ethanol Consumption (Trillion Btu)

Year	Trillion Btu
1990	63
1995	117
2000	139
2001	147
2002	175
2003	239
2004	299
2005	340

Uncertainty

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would increase emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Recalculations Discussion

Commercial wood consumption values were revised for the full time series, based on updated information from EIA's Commercial Building Energy Consumption Survey (EIA 2006). EIA (2006) also reported minor changes in wood consumption by the residential and industrial sectors for the full time series, and in ethanol consumption for 2001 through 2004.

[BEGIN BOX]

Box 3-4: Formation of CO_2 through Atmospheric CH_4 Oxidation

CH_4 emitted to the atmosphere will eventually oxidize into CO_2, which remains in the atmosphere for up to 200 years. The global warming potential (GWP) of CH_4, however, does not account for the radiative forcing effects of the CO_2 formation that results from this CH_4 oxidation. The IPCC *Guidelines for Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) do not explicitly recommend a procedure for accounting for oxidized CH_4, but some of the resulting CO_2 is, in practice, included in the inventory estimates because of the intentional "double-counting" structure for estimating CO_2 emissions from the combustion of fossil fuels. According to the IPCC Guidelines, countries should estimate emissions of CH_4, CO, and NMVOCs from fossil fuel combustion, but also assume that these compounds eventually oxidize to CO_2 in the atmosphere. This is accomplished by using CO_2 emission factors that do not factor out carbon in the fuel that is released as in the form of CH_4, CO, and NMVOC molecules. Therefore, the carbon in fossil fuel is intentionally double counted, as an atom in a CH_4 molecule and as an atom in a CO_2 molecule.[51] While this approach does account for the full radiative forcing effect of fossil fuel-

[51] It is assumed that 100 percent of the CH_4 emissions from combustion sources are accounted for in the overall carbon emissions calculated as CO_2 for sources using emission factors and carbon mass balances. However, it may be the case for some types of combustion sources that the oxidation factors used for calculating CO_2 emissions do not accurately account for the full

related greenhouse gas emissions, the timing is not accurate because it may take up to 12 years for the CH_4 to oxidize and form CO_2.

There is no similar IPCC approach to account for the oxidation of CH_4 emitted from sources other than fossil fuel combustion (e.g., landfills, livestock, and coal mining). CH_4 from biological systems contains carbon that is part of a rapidly cycling biological system, and therefore any C created from oxidized CH_4 from these sources is matched with carbon removed from the atmosphere by biological systems—likely during the same or subsequent year. Thus, there are no additional radiative forcing effects from the oxidation of CH_4 from biological systems. For example, the C content of CH_4 from enteric fermentation is derived from plant matter, which itself was created through the conversion of atmospheric CO_2 to organic compounds.

The remaining anthropogenic sources of CH_4 (e.g., fugitive emissions from coal mining and natural gas systems, industrial process emissions) do increase the long-term CO_2 burden in the atmosphere, and this effect is not captured in the inventory. The following tables provide estimates of the equivalent CO_2 production that results from the atmospheric oxidation of CH_4 from these remaining sources. The estimates for CH_4 emissions are gathered from the respective sections of this report, and are presented in Table 3-57. The CO_2 estimates are summarized in Table 3-58.

Table 3-57: CH_4 Emissions from Non-Combustion Fossil Sources (Gg)

Source	1990	1995	2000	2001	2002	2003	2004	2005
Coal Mining	3,899	3,165	2,662	2,644	2,476	2,480	2,597	2,494
Abandoned Coal Mines	286	391	349	318	292	282	275	263
Natural Gas Systems	5,927	6,101	6,027	5,971	5,951	5,891	5,669	5,292
Petroleum Systems	1,640	1,482	1,325	1,303	1,275	1,229	1,209	1,357
Petrochemical Production	41	52	58	51	52	51	55	52
Silicon Carbide Production	1	1	1	+	+	+	+	+
Iron and Steel Production	63	62	57	51	48	49	50	45
Total	**11,858**	**11,254**	**10,479**	**10,339**	**10,094**	**9,982**	**9,855**	**9,504**

Note: These emissions are accounted for under their respective source categories. Totals may not sum due to independent rounding.

Table 3-58: Formation of CO_2 through Atmospheric CH_4 Oxidation (Tg CO_2 Eq.)

Source	1990	1995	2000	2001	2002	2003	2004	2005
Coal Mining	10.7	8.7	7.3	7.3	6.8	6.8	7.1	6.9
Abandoned Coal Mines	0.8	1.1	1.0	0.9	0.8	0.8	0.8	0.7
Natural Gas Systems	16.3	16.8	16.6	16.4	16.4	16.2	15.6	14.6
Petroleum Systems	4.5	4.1	3.6	3.6	3.5	3.4	3.3	3.7
Petrochemical Production	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.1
Silicon Carbide Production	+	+	+	+	+	+	+	+
Iron and Steel Production	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Total	**32.6**	**30.9**	**28.8**	**28.4**	**27.8**	**27.4**	**27.1**	**26.1**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 Tg CO_2 Eq.

The estimates of CO_2 formation are calculated by applying a factor of 44/16, which is the ratio of molecular weight of CO_2 to the molecular weight of CH_4. For the purposes of the calculation, it is assumed that CH_4 is oxidized to CO_2 in the same year that it is emitted. As discussed above, this is a simplification, because the average atmospheric lifetime of CH_4 is approximately 12 years.

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mass of carbon emitted in gaseous form (i.e., partially oxidized or still in hydrocarbon form).

CO_2 formation can also result from the oxidation of CO and NMVOCs. However, the resulting increase of CO_2 in the atmosphere is explicitly included in the mass balance used in calculating the storage and emissions from non-energy uses of fossil fuels, with the carbon components of CO and NMVOC counted as CO_2 emissions in the mass balance.[52]

[END BOX]

[52] See Annex 2.3 for a more detailed discussion on accounting for indirect emissions from CO and NMVOCs.

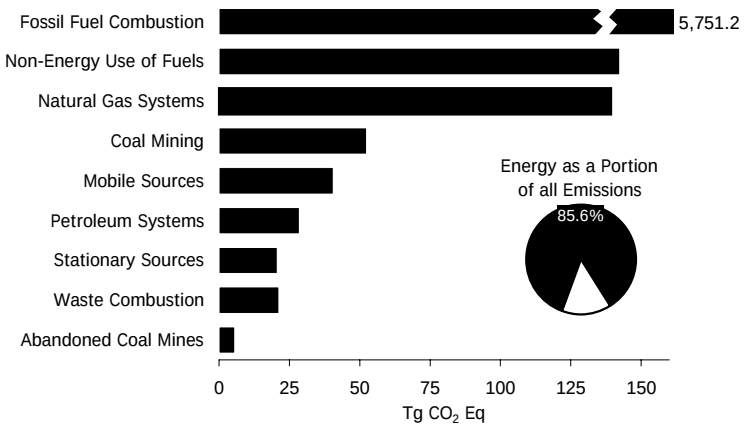

Figure 3-1: 2005 Energy Sector Greenhouse Gas Sources

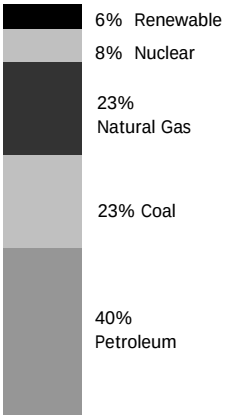

Figure 3-3: 2005 U.S. Energy Consumption by Energy Source

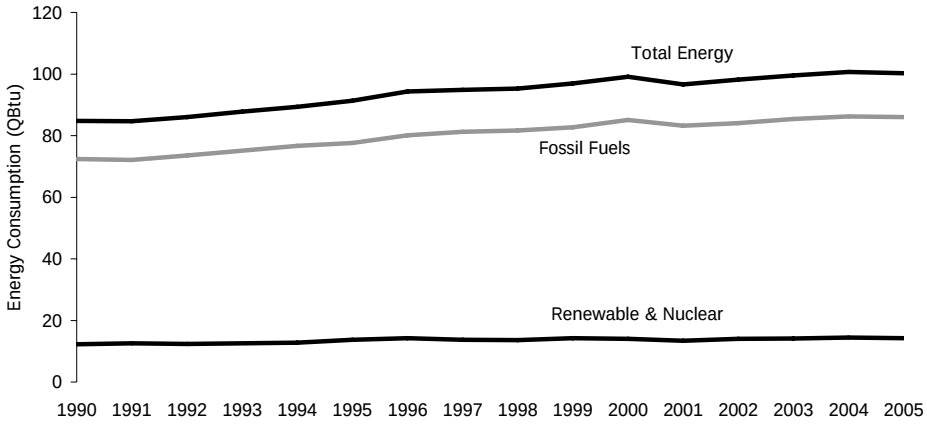

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)
Note: Expressed as gross calorific values

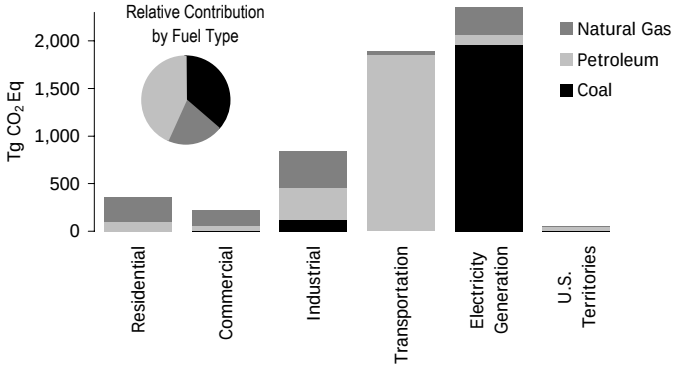

Figure 3-5: 2005 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type
Note: The electricity generation sector also includes emissions of less than 0.01 Tg CO_2 Eq. from geothermal-based electricity generation

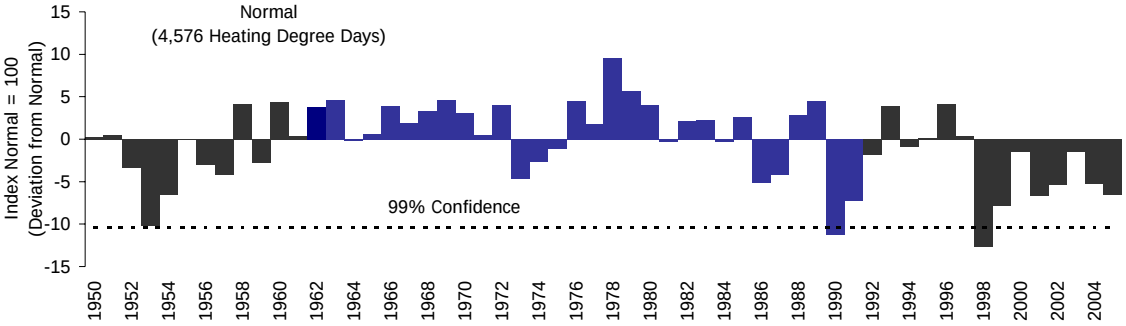

Figure 3-6. Annual Deviations from Normal Heating Degree Days for the United States (1950-2005)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1961 through 1990.

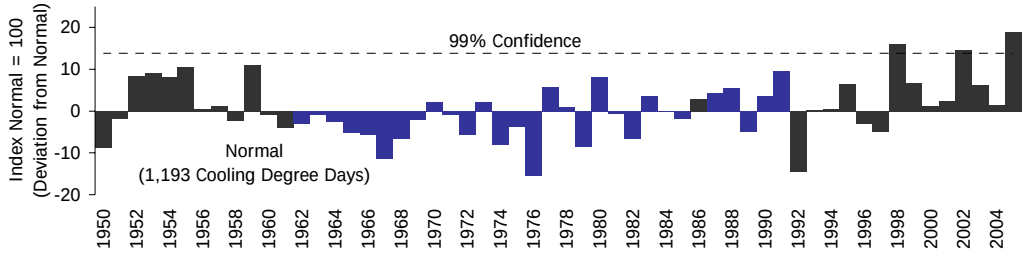

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2005)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1961 through 1990.

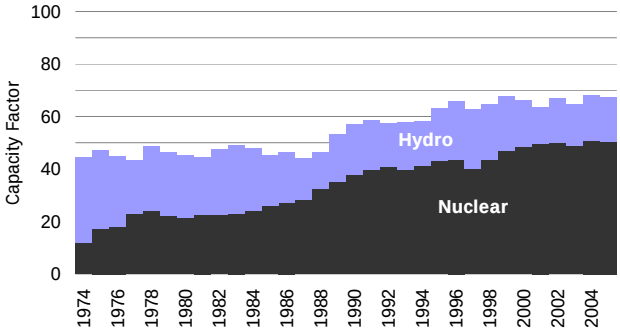

Figure 3-8: Aggregate Nuclear and Hydroelectric Power Plant Capacity Factors in the United States (1974-2005)

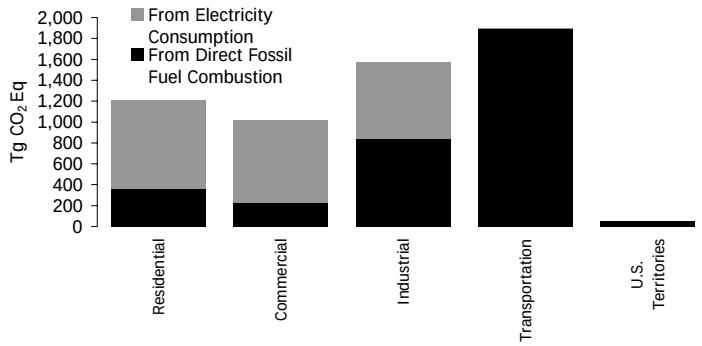

Figure 3-9: 2005 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

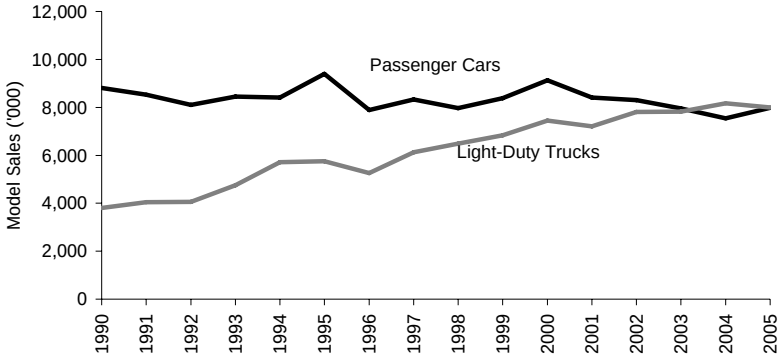

Figure 3-10: Sales of New Automobiles and Light-Duty Trucks, 1990-2005

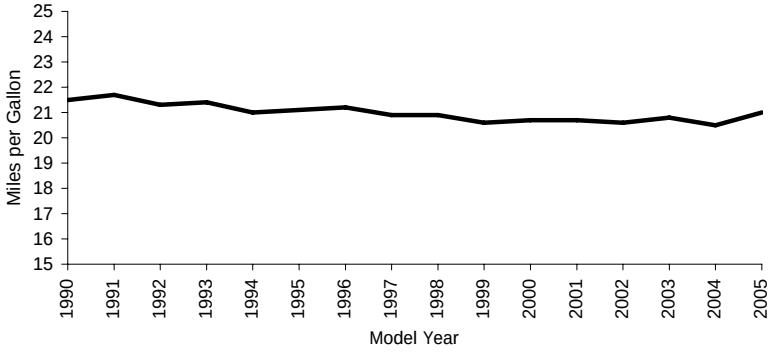

Figure 3-11: Sales-Weighted Fuel Economy of New Automobiles and Light-Duty Trucks, 1990-2005

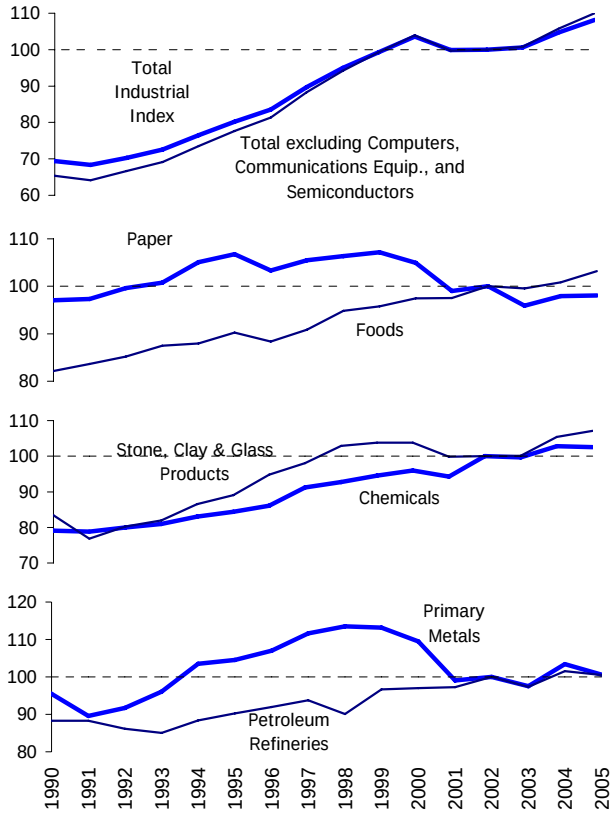

Figure 3-12: Industrial Production Indexes (Index 2002=100)

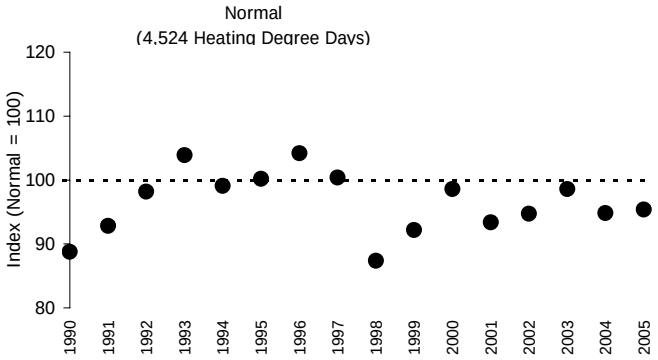

Figure 3-13: Heating Degree Days
Note: Excludes Alaska and Hawaii

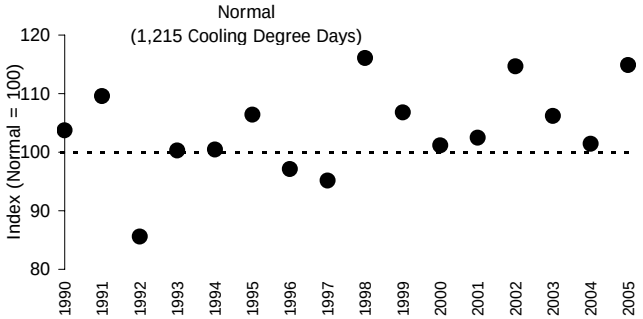

Figure 3-14: Cooling Degree Days
Note: Excludes Alaska and Hawaii

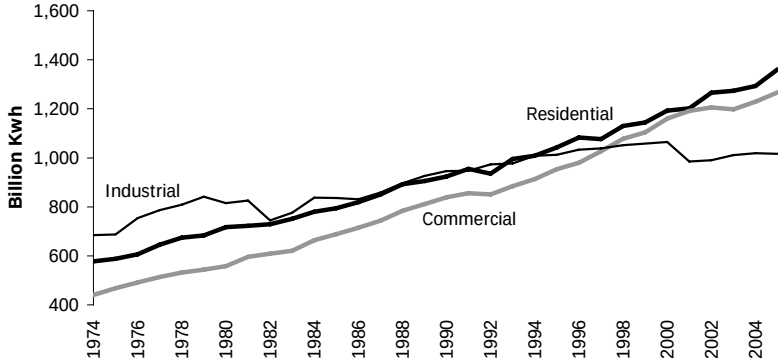

Figure 3-15: Electric Generation Retail Sales by End-Use Sector
Note: The transportation end-use sector consumes minor quanties of electricity.

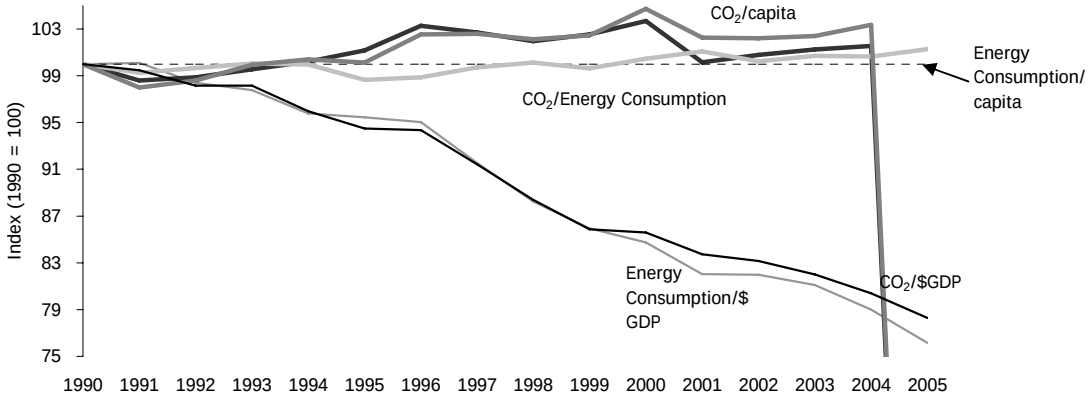

Figure 3-16: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

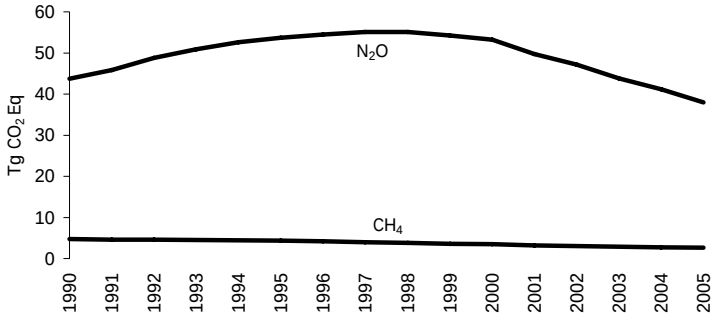

Figure 3-17: Mobile Source CH_4 and N_2O Emissions